BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap.	R.15-03-011 (Filed March 26, 2015)

COMPLIANCE REPORT OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) ON BEHALF OF THE MULTIPLE-USE APPLICATION WORKING GROUP

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Dated: **August 09, 2018**

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Southern California Edison Company (SCE) respectfully submits the Compliance Report of SCE, San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) (collectively the IOUs) on behalf of the Multiple-Use Application (MUA) Working Group pursuant to Ordering Paragraph 4 in the California Public Utilities Commission's (CPUC or Commission) Decision (D.) 18-01-003, which directed the IOUs to file the Compliance Report on behalf of the Working Group the Energy Division convened within six months of the Working Groups' first meeting on February 9, 2018. This Compliance Report filing timely complies with that directive. The Compliance Report is attached hereto as Appendix A.

Respectfully submitted,

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Appendix A

Multiple-Use Applications for Energy Storage: Final Working Group Report

Multiple-Use Applications for Energy Storage: Final Working Group Report

Decision D.18-01-003 in Rulemaking R.15-03-011

August 9, 2018

Lead Contributors:

Pacific Gas & Electric Company, California Energy Storage Alliance, San Diego Gas & Electric Company, Southern California Edison Company, California Independent System Operator, Stem, Olivine, Sunrun, Green Power Institute, Advanced Microgrid Solutions, Demand Energy

Facilitator:

Energy Division of California Public Utilities Commission

Introduction

The California Public Utilities Commission (CPUC or Commission) Decision on Multiple-Use Application (MUA) Issues (Decision (D.) 18-01-003) adopted: (1) a joint proposal of the staff of the CPUC and the California Independent System Operator (CAISO) and (2) eleven rules to guide the formation of multiple use applications for energy storage. The eleven rules are as follows:

Rule 1. Resources interconnected in the customer domain may provide services in any domain.

Rule 2. Resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources, per Ordering Paragraph 11 of D.17-04-039.

Rule 3. Resources interconnected in the transmission domain may provide services in all domains except the customer or distribution domains.

Rule 4. Resources interconnected in any grid domain may provide resource adequacy, transmission and wholesale market services.

Rule 5. If one of the services provided by a storage resource is a reliability service, then that service must have priority.

Rule 6. Priority means that a single storage resource must not enter into two or more reliability service obligation(s) such that the performance of one obligation renders the resource from being unable to perform the other obligation(s). New agreements for such obligations, including contracts and tariffs, must specify terms to ensure resource availability, which may include, but should not be limited to, financial penalties.[1]

Rule 7. If using different portions of capacity to perform services, storage providers must clearly demonstrate, when contracting for services, the total capacity of the resource, with a guarantee that a certain, distinct capacity be dedicated and available to the capacity-differentiated reliability services.

Rule 8. For each service, the program rules, contract or tariff relevant to the domain in which the service is provided, must specify enforcement of these rules, including any penalties for non-performance.

Rule 9. In response to a utility request for offer, the storage provider is required to list any additional services it currently provides outside of the solicitation. In the event that a storage resource is enlisted to provide additional services at a later date, the storage provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this Rule is to provide transparency in the energy storage market.

Rule 10. For all services, the storage resource must comply with availability and performance requirements specified in its contract with the relevant authority.

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1 SDG&E identified a possible language issue that could confuse the intent of the rule. Specifically, the phrase, "one obligation renders the resource from being unable to perform the other obligation(s)" should be reworded so that "from being" is struck and modified to the following: "one obligation renders the resource unable to perform the other obligation(s)."

Rule 11. In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

D.18-01-003 also ordered the CPUC Energy Division (ED), in coordination with the CAISO, to convene a Working Group (WG) to further develop and address several issues, and to prepare a report on the state of the energy storage industry with clear recommendations for new rules, modifications to existing rules, and / or further CPUC action. Those issues are included, but not limited to, the following:

- Appropriate metering, measurement, and accounting for MUA beginning with time-differentiated MUA, then capacity-differentiated MUA and, finally, simultaneous MUA;
- CPUC-jurisdictional enforcement of MUA rules, beyond that which is stated in this proposal. Such enforcement includes, but is not limited to, contract provisions;
- Incrementality – any refinements to the preliminary rule set forth in this proposal;
- Any modifications to CPUC-jurisdictional rules or tariffs in order to actualize the rules and principles set forth in this proposal;
- Enabling a subset of a distributed energy resource aggregation to provide distribution-level services; and
- Any other issues within the CPUC's jurisdiction that the WG identifies.

The WG met over the course of six months to discuss the aforementioned issues, which are included in this final MUA Working Group Report. The Report is divided into five chapters, which are listed below:

Report Sections:

- Chapter 1. Behind the Meter: Metering, Measurement and Settlement page 1
- Chapter 2. In Front of the Meter: Metering, Measurement and Settlement page 28
- Chapter 3. Incrementality: Utility Position page 40
- Chapter 4. Incrementality: Industry Position page 60
- Chapter 5. Ensuring Resource Performance: Rules 6-10 page 80

Multiple Use Applications for Energy Storage Working Group Chapter 1. Behind the Meter: Metering, Measurement and Settlements	
Lead Drafter:	Fabienne Arnoud and John Hernandez, Pacific Gas and Electric (PG&E)
Contributors:	Alex Morris and Jin Noh, California Energy Storage Alliance (CESA) Louis Bick, Jan Strack and Jim Spurgeon, San Diego Gas & Electric (SDG&E) Eric Little and Max Carpenter, Southern California Edison (SCE) Jill Powers, Peter Klauer, and Eric Kim, California ISO (CAISO) Ted Ko, Stem Robert Anderson and Naor Deleanu, Olivine Steven Rymsha, Sunrun Tam Hunt, Green Power Institute

1. Synopsis

This chapter of the MUA WG Report includes discussion and recommendations focusing on the MUA use cases that pertain to behind-the-meter (BTM) energy storage (ES) and records key takeaways from the WG sessions that specifically discussed "Metering, Measurement and Settlement".

This chapter addresses the following issues and recommendations:

- **Issue 1:** Should Demand Response (DR) participation be identified as a service under the Customer Domain?

  Recommendations: The WG recommends removing DR as a service within the Customer Domain because DR is a procurement channel to obtain grid services.

- **Issue 2:** When participating in the CAISO market and providing energy and/or ancillary services, which CAISO agreements and models should be used by the Investor Owned Utilities (IOUs) and third-party providers that have resources made up of retail customers and BTM storage?

  Recommendations: The IOUs recommend that for any CAISO participating resource that is comprised of retail customers and BTM storage, the CAISO's Demand Response Provider Agreement (DRP-A) should be used rather than the CAISO's Distributed Energy Resource Provider Agreement (DERP-A). CAISO recognizes the regulatory and technical challenges presented by DERP-A and the additional work it would require.

  Olivine and Sunrun, conditionally agree with this recommendation granted that dispatchable energy export should be explored for compensation under DR procurement and CAISO participation model.

  CESA is not in full agreement with this recommendation. CESA supports both CAISO agreements and models but the DERP-A with the non-generator resource (NGR) participation model is more flexible for systems that desire to export for wholesale energy compensation[2], when export is not currently compensated by wholesale markets[3] under DRP-A and the proxy demand resource

2 Net Energy Metering (NEM) customers are not eligible to participate under DERP-A.

3 NEM customers registered in a PDR under DRP-A get compensation for their exports to the grid by the NEM retail rate.

(PDR) model. CESA, however, does not oppose the exploration of compensation of dispatchable energy export under the DR procurement.

- **Issue 3:** Is it premature to develop meter, measurement and settlement for retail customers and their BTM ES as distribution services are still under development in various CPUC proceedings?

  Recommendations: The WG recommends that no action be taken until decisions are rendered by the CPUC under the Distribution Resource Plan (R.14-08-013) and Integrated Distributed Energy Resource (R.14-10-003) proceedings. However, the findings, observations, and recommendations from this report should inform and coordinate with the DRP/IDER proceedings.

- **Issue 4:** Should retail customers and their BTM ES be eligible and compensated for energy exported to the grid as wholesale energy?

  Recommendations: Olivine and Sunrun recommend that the CPUC and CAISO consider the inclusion and compensation of energy exported as part of DR and CAISO's participation model.

- **Issue 5:** Meter Generator Output (MGO) is approved by the Federal Energy Regulatory Commission (FERC) and implemented by the CAISO to allow sub-metering of energy storage. Should there be a reciprocating CPUC approval to use MGO for retail settlement purposes if MGO is used in the Resource Adequacy (RA) compensation methodology?

  Recommendations: The IOUs, with support from CAISO and Olivine, recommend that for purposes of compensating retail services provided by BTM ES, the CPUC address any CAISO DR settlement methodology (MGO or ESDER Phase 2 alternative baselines) that will be used for the measurement and settlement of RA resources.
  CESA does not believe that CPUC approval is needed. While CPUC approval would support authorization of different configurations, CESA does not see the need for the CPUC to approve every metering arrangement in order to adequately measure and settle BTM ES.
  Sunrun does not believe CPUC approval is needed to approve every metering arrangement, however the CPUC may need to intervene if there are any contested issues around metering arrangements between IOUs and parties.

- **Issue 6:** Current DR settlement links energy performance measurement to RA capacity measurement, which is used to calculate compensation. Should the linkage between energy performance and RA capacity measurement be decoupled?

  Recommendations: PG&E and SDG&E recommend further investigation as to whether DR capacity measurement be decoupled from energy measurement. As it stands, DR providing RA capacity is subject to different requirements than IFM ES providing RA capacity. Stem and Sunrun agree with this proposal and suggest this topic be addressed within the CPUC's RA proceeding.

2. Methodology

ED, with input from the WG participants, identified seven BTM ES use cases which cover different combinations of services that BTM storage could provide across multiple grid service domains using one of the 3 MUA differentiation categories (time, capacity, or simultaneous).

The WG examined where the seven BTM use cases are in their development stage of implementation readiness. Specifically, current rules and operational processes for each grid service in terms of metering, measurement, and settlements were discussed (WG session 2) and the three MUA differentiation categories were consequently overlaid (WG sessions 4 and 5) with the following goals:

- Identify gaps where remaining policy and operational issues still require additional analysis and consideration before the implementation of the MUA rules adopted in D.18-01-003, and
- Recommend the regulatory venues at the CPUC or CAISO where the remaining policy and operational issues should be addressed. Coordination will be required between MUA and other proceedings.

Topics not systematically discussed, but where resolution is needed, are also listed in this report so they can be addressed in the future.

During the March 5, 2018 WG, it was noted that the WG discussions to enable CAISO BTM ES participation specifically address the topic as it applies to bundled customers only. The CPUC has limited jurisdiction over Community Choice Aggregation (CCA) providers and it is unknown whether the rules adopted for the IOU programs for ES MUA could translate to similar models and configurations for CCA programs.

3. Assessment of Implementation Readiness of the MUA Services

Table 1: CPUC's MUA Decision's List of Domains and Services

Domain	Reliability Services	Non-Reliability Services
Customer	None	TOU bill management; Demand charge management; Increased self-consumption of on-site generation; Back-up power; Supporting customer participation in DR programs
Distribution[7]	Distribution capacity deferral; Reliability (back-tie) services; Voltage support; Resiliency/microgrid/islanding	None
Transmission	Transmission deferral; Inertia*; Primary frequency response*; Voltage support*; Black start	None
Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves; Flexible ramping product	Energy
Resource Adequacy	Local capacity; Flexible capacity; System capacity	None

([7]) For distribution-level services, the rules, procurement procedures and the services themselves are currently in development in a separate Commission R.14-10-003, the Integrated Distributed Energy Resources (IDER). Ordering Paragraph 2 of D.16-12-036 in R.14-10-003 defines these four products types. Should the product types be modified in R.14-10-003 subsequent proceeding, the product types on the distribution system available to storage devices / resources will automatically update.

* The CAISO currently does not operate a centralized wholesale market for inertia, primary frequency response and voltage support. The CAISO does procure some primary frequency response on a bilateral contract basis.

The MUA decision lists 21 reliability and non-reliability services across 5 service domains.

Examining current rules and operational processes, each service can be split into three categories signifying its level of implementation readiness:

- Category 1: Service is implemented and ready
- Category 2: Service is under development in an active proceeding
- Category 3: Service is not currently being addressed in an active regulatory proceeding

3.1 Assessment of the "Customer" Domain

In the MUA decision, "Supporting customer participation in DR programs" is listed as a service in the customer domain that BTM storage can provide. This created some confusion in the WG's discussions because:

- DR programs are akin to a *sourcing* mechanism, similar in that sense to a BTM ES device submitting a proposal in response to a Request for Offer (RFO).
- DR uses retail tariffs and contracts today and can provide reliability services such as the resource adequacy, ancillary services and energy services,[4] services which are listed in the "Resource Adequacy" and "Wholesale Market" service domains.

<u>Recommendation 1: Treat DR as a Procurement Channel and Remove DR as a Service in the Customer Domain</u>

<u>Status: Consensus</u>

During the April 20, 2018 WG, Stem advocated that "Supporting customer participation in DR Programs" be removed as a service in the customer domain. Critical peak pricing is Load Modifying DR and is more akin to TOU bill management functionally. All other DR programs are integrated into the market and are counted for RA. CAISO requested that this be documented. PG&E and CESA agree that "Supporting customer participation in DR Programs" should be removed from the Customer domain services.

The WG's recommendation is to delete "Supporting customer participation in DR programs" from the list of services under the MUA services, in the same way that other procurement channels, like BTM storage devices submitting a proposal in response to a RFO, are not listed as services either.

The WG also discussed whether "increased self-consumption of on-site generation" should be removed from the list of customer-domain services since some WG stakeholders viewed this as a form of TOU bill management. It may be reasonable to keep PV self-consumption as its own standalone customer-domain service since self-consumption is not always an economic decision in response to rates. That is, PV self-consumption is not always maximizing TOU bills and often the objective is to maximize the amount of solar that is consumed onsite for other reasons (*e.g.*, maximizing the Federal Investment Tax Credit). Although there may be similarities in how a paired battery dispatches to the way a battery might be dispatched under the TOU bill management use case, there are many times where customer bill savings are not being optimized/maximized.

[4] For BTM ES to provide and meet their obligation to deliver Resource Adequacy, the BTM ES must be able to participate and bid in the CAISO market in adherence to CAISO's Must Offer Obligation requirements.

Table 2: Customer Domain: Implementation Readiness

Domain	Services	Implementation Readiness Category
Customer	- TOU bill management - Demand charge management - Increased self-consumption of on-site generation - Back-up power	- Category 1 / Ready - Category 1 / Ready - Category 1 / Ready - Category 1 / Ready

3.2 Assessment of the "Resource Adequacy" & "CAISO Wholesale Markets" Domains

There are two CAISO-filed pro forma agreements approved by the FERC and implemented by CAISO that allow BTM storage to participate in various CAISO wholesale markets. One agreement, the DRP-A allows certain resources, including BTM storage, to participate as a Demand Response Provider (DRP) or to join an aggregation of such resources overseen by a DRP. The other agreement allows storage and all sorts of distributed energy resources to participate in various CAISO Wholesale Markets as a DERP-A or to join an aggregation of such resources overseen by a DERP. In both cases, the CAISO forms a contractual relationship with the DRP or DERP, not the individual resource.

The focus of this section is on BTM storage resources. BTM in this context refers to a resource that is interconnected in a manner that it is not authorized to export power as a wholesale energy service to the grid. These resources interconnect under Rule 21 and are restricted from exporting wholesale energy to the grid. In this context, a BTM storage device cannot aggregate its output with onsite load such that there is an export to the grid for sale into the wholesale market. Rather, the BTM storage device can be utilized to serve onsite load thereby reducing the amount of load served from the grid. This reduction in load served from the grid can then be utilized for retail purposes (e.g. peak load shaving) or participation in the wholesale market as a DR resource. A resource seeking to export power to the grid and to participate in wholesale markets with such export would need to interconnect under a wholesale access tariff and in doing so would be metered as its own facility turning it into an in-front of the meter (IFM) resource[5]. The remainder of this discussion utilizes this distinction for BTM storage resources.

5 In its July 26, 2018 comments, CESA disagrees with the characterization that interconnecting under WDAT makes it an IFOM resource.

Table 3: CAISO Agreements Allowing BTM Storage to Participate in Wholesale Markets

	CAISO Agreements	
	Demand Response Provider Agreement (DRP-A)	**Distributed Energy Resource Provider Agreement (DERP-A)**
Approved by FERC	July 15, 2010	September 22, 2016
CAISO Model(s)	• Proxy Demand Resource (PDR) • Reliability DR Resource (RDRR)	• Non-Generator Resource (NGR) • Participating Generator (PG)
DER Aggregation	Allows the aggregation of retail customers, including customers that may have Behind-the-Meter (BTM) storage[6]	Allows the aggregation of BTM storage and In-Front-of-the-Meter (IFM) storage[7]

CPUC Rule 24[8] for BTM storage participating under CAISO's DRP-A[9] [10] resolves issues such as access to customer data, oversight of Third-Party Providers, interactions between Third-Party Providers and the Utility, etc., yet no discussion with the CPUC has focused exclusively on BTM storage resource participation in a DERP aggregation under the CAISO's DERP-A. This leaves gaps and questions for implementing DERP-A for BTM storage. Listed below are examples of gaps for DERP-A that were discussed during the WG meetings:

- Settlement under DRP-A is *strictly* on the dispatched load shift; the charging of a BTM battery enrolled in DR remains governed by the customer's retail rate: DRP-A allows the LSE function to remain intact with no risk of wholesale charging and discharging to serve retail load. Under CAISO's DERP-A, BTM storage resource continue to pay retail rates for all kWh and kW for charging, as the CAISO only has a relationship with the DERP. In each case, the wholesale service provided to the CAISO is the curtailment of load. The CAISO settles based upon metering and measurement methods established to evaluate the load curtailment. In the case of a battery utilized to provide DR, the utility rate governs the retail impacts of consumption, including for charging and reductions in consumption due to discharging to onsite load.
- CESA requests that the CAISO and CPUC outline the reasons why DERP-A does not qualify for RA. The WG discussed how one of the key barriers is the lack of a methodology to study deliverability of aggregated resources.
- Sunrun stated that new DERP-A rules can address situational awareness concerns with metering and reporting methods as well as ensuring appropriate cost recovery and payments for services provided.

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6 DRP-A allows for aggregation of any BTM technology types (Storage, Gen, Load, etc.)

7 DERP-A allows for aggregation of any IFM and BTM technology types (Storage, Gen, Load, etc.)

8 Rule 24 was developed by the CPUC after FERC ordered DR be integrated into the market (FERC Order 719). It specifies rules around DR market integration enablement, data sharing, customer privacy, roles and responsibilities when DR is provided by a third party, as well as rules prohibiting double compensation from retail and wholesale market participation.

9 CPUC opened Phase IV of DR R.07-01-041 on Nov 9, 2009 and worked with Parties to address applicability issues for DRP-A and, with the approval on Nov 29, 2012 of D.12-11-025, to construct CPUC Electric Rule 24.

10 In SDG&E's case, an Electric Rule 24 was already in existence, leading SDG&E to assign the next available Electric Rule number in sequence, which was Electric Rule 32.

Table 4: DRP-A and DERP-A: Regulatory Readiness

	Demand Response Provider Agreement (DRP-A)	Distributed Energy Resource Provider Agreement (DERP-A)
CAISO Participation Model(s)	• PDR / RDRR for load reduction • CPUC's Load Shifting WG looking at load consumption / bi-directional non-exporting[11] new products in coordination with CAISO's ESDER.	• Non-Generator Resource (NGR) • Participating Generator (PG)
MUA services	• DRP-A qualifies for RA • DRP-A is the most active agreement for the majority of resources providing MUA services • DRP-A is not subject to the CAISO's 24 x 7 availability requirement and is based rather on the retail DR program operating hours and RA availability assessment hours.	• DERP-A does not qualify for RA[12] • Should DERP-A eventually find a path to qualify for RA, the resource's settlement requirement of 24 x 7 availability would create barriers for multiple uses by different grid operators.[13]
CPUC's Rule allowing actual bidding of Utility's retail customers (Direct Participation)	Electric Rule 24 / Rule 32	CPUC has not discussed whether additional actions are needed.

The table below, with its associated notes, summarizes the implementation readiness of the MUA services for BTM storage for each CAISO agreement.

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11 "Bi-directional non-exporting" means the import of power from the distribution system at the customer's retail meter can be increased or decreased ("bi-directional"), but not decreased to the point where the import becomes an export ("non-exporting").

12 CAISO's decision for DERP to not qualify for RA was a scoping decision only. The CAISO expected that there would be a follow-on effort by the CPUC (working with the CAISO) to determine the rules by which DER aggregations could qualify for RA recognizing their unique deliverability challenges.

13 To support multiple use applications, the CAISO stated the following: must consider extending a non-24x7 participation requirement to DERP-A participation models (NGR and PG), which would include a thorough examination of this extensions impact on established 24x7 participation market concepts including but not limited to contracts, systems and CAISO business practices.

Table 5: DRP-A and DERP-A: Implementation Readiness for MUA Services

Domain	Services	CAISO BTM ES Participation	
		DRP-A with PDR Implementation Readiness Category	DERP-A with NGR/PG Implementation Readiness Category
Wholesale Market	- Frequency regulation - Spinning reserves - Non-spinning reserves - Flexible ramping product	- Technically Feasible / Category 3 / Not in an active state **– Cf. Note 1** - Yes / Category 1 / Ready - Yes / Category 1 / Ready - Yes / Category 1 / Ready	- Technically Feasible/ Category 3/ Not in an active proceeding **– Cf. Note 2** - Technically Feasible/ Category 3/ Not in an active proceeding **– Cf. Note 2** - Technically Feasible/ Category 3/ Not in an active proceeding **– Cf. Note 2** - Technically Feasible/ Category 3/ Not in an active proceeding **– Cf. Note 2**
Wholesale Market	- Energy	- Yes, for load reduction / Category 2 for load increase / In active development **– Cf. Note 1**	- Technically Feasible/ Category 3/ Not in an active proceeding **– Cf. Note 2**
Resource Adequacy	- Local capacity - Flexible capacity - System capacity	- Yes / Category 1 / Ready - Yes / Category 1 / Ready - Yes / Category 1 / Ready	- Category 3/ Not in an active proceeding **– Cf. Note 3** - Category 3/ Not in an active proceeding **– Cf. Note 3** - Category 3/ Not in an active proceeding **– Cf. Note 3**

- **Note 1**: CPUC R.13-09-011, which resulted in D.17-10-017 in late 2017, is a proceeding that instituted a Load Shifting Working Group (LSWG) starting in 2018 to develop new load consumption / bi-directional non-exporting DR products in coordination with the CAISO's ESDER 3 initiative. This could result in DR being able to dispatch energy load increase in the future, and provide frequency regulation (though frequency regulation is not currently in scope of the LSWG nor ESDER 3).
- **Note 2**: There is no active proceeding to discuss what the CPUC needs to do (equivalent to Rule 24 for DRP-A) for CAISO's DERP-A for BTM exporting storage.
- **Note 3:** DERP-A does not qualify for Resource Adequacy, with no active CPUC proceeding to discuss DERP-A for BTM.

Recommendation 2: IOUs' recommendation--Enable BTM storage using DRP-A Rather Than DERP-A

Status: Partial consensus

In light of this assessment of implementation readiness, the IOUs recommend that CAISO's DRP-A should be used rather than DERP-A to enable BTM storage participation into CAISO wholesale markets for the following main reasons:

(i) Over the past 9 years, the CPUC has worked closely with the CAISO, stakeholders and IOUs to implement the necessary accompanying rules (Rule 24, no risk of wholesale charging / retail discharging), processes and systems to address the complexities of BTM DRs' CAISO participation via the DRP-A. No such efforts have been systematically undertaken for DERP-A.

(ii) The DRP-A is successfully used today by non-exporting BTM storage and other DR providers because it can help them make the most of their assets. Most importantly, DRP-A qualifies for RA whereas DERP-A does not. RA payments are important to finance storage or other technologies, and get projects to market in a timely fashion.

(iii) DR is also expanding to best accommodate the physical and operational characteristics of DER aggregations. Collaborative stakeholder processes at both the CPUC and CAISO are considering enhancements so DR goes beyond load reduction and proposes bi-directional non-exporting services that could be more frequently dispatched. DR can then be the procurement channel for storage resources wishing to provide multiple uses whereas the DERP-A's requirement for 24/7 availability to the CAISO could create barriers for multiple uses by different grid operators.

(iv) DR resource providing load reduction does not raise the same safety and reliability concerns as a resource providing bi-directional services (energy export + load take) on the distribution system. Providing services beyond load reduction, whether under DRP-A or DERP-A, will require new performance and deliverability requirements as well as IT systems for visibility and control.

Even if DERP-A were to address the gaps identified above, it would result in a duplicative effort arguably equivalent to what the DRP-A already provides for BTM DER aggregations.[14]
The recommendation is therefore that BTM DERs use the DRP-A rather than the DERP-A to participate in CAISO markets: using DRP-A optimizes the investments ratepayers have already made over the past 9 years with the implementation of CPUC's rules, processes and systems. Avoiding unnecessary duplicative ratepayers' investments to support DERP-A for BTM storage and other BTM DERs is important for ensuring reasonable rates.

Given the limited value that the DERP-A presents today and the existing challenges to implement, SDG&E favors giving priority to further develop the DRP-A model as opposed to trying to rehash through DERP-A. SDG&E believes decisions around treatment of energy exported for purposes of wholesale market participation, should be left to the CAISO.

The CAISO states that DERP framework was specifically developed to accommodate IFM and BTM DER aggregations. CAISO recognizes the technical (i.e., 24x7 market participation requirement) and regulatory challenges DERP-A has compared to DRP-A. Additional steps are required at the CPUC to remove existing barriers to enable DERP-A.

Olivine supports the utilization of DRP-A over DERP-A. Olivine added that dispatchable energy export service should be considered and added as part of DRP-A. By doing so, it is much more logical to enhance DRP-A's PDR model than the current DERP-A BTM construct. Sunrun partially supports this position noting that "focusing on the evolution of the (DRP) likely makes sense but that we should make sure the WG report does not limit broader future enablement of DERP". Based on Sunrun's

[14] DERP-A is not duplicative with DRP-A for IFM storage or other IFM DERs.

comment on May 23, 2018, DRP-A can be the preferred CAISO agreement and participation model if it allows for the inclusion of dispatchable energy export.

Some industry stakeholders on May 17, 2018, expressed similar opinion that DRP-A would be a more attractive pathway to the CAISO market if dispatchable energy export is allowed and compensated for.

SCE proposes that the CAISO allow demand resources (referring here to load reduction, not PDR or RDRR) in DERP-A to use CAISO DR baselines for the measurement, metering, and settlements rather than direct metering.

In its comments to this report on May 21, 2018, CESA indicated that it is not in full agreement that rules still need to be developed by CPUC for the viability of the DERP-A. CESA does not dispute that some CPUC engagement or regulation may be appropriate in the right instances but some of these barriers may be addressed elsewhere. While DRP-A is well developed compared to DERP-A, CESA disagrees with the characterization that DERP-As are totally unready and that much CPUC work remains. CESA believes making the DERP-A model viable is important because it works for aggregations and is more flexible for systems that may export or incorporate various technologies.

3.3 Assessment of the "Distribution" Domain

The classification for the implementation readiness of the services in the Distribution domain is Category 2, as the services are under development in the CPUC's Distribution Resources Plan (R.14-08-013) and Integrated Distributed Energy Resources (R.14-10-003) proceedings. Utilities are building experience in contracting for distribution deferral to help develop specific operational characteristics such as, but not limited to, visibility, control, timeline of dispatch, duration, frequency and latency of responses which may be required from BTM ES.

Table 6: Distribution Readiness: Implementation Readiness

Domain	Services	Implementation Readiness Category
Distribution	- Distribution Capacity Deferral - Reliability (back-tie) services - Voltage Support - Resiliency / microgrid / islanding	- Category 2 / In active development - Category 2 / In active development - Category 2 / In active development - Category 2 / In active development

Recommendation 3: When Considering MUAs Providing Distribution Services, Await Outcomes of DRP and IDER

Status: Consensus

Recognizing that no uniform set of processes, characteristics, and operational requirements for distribution services have yet been established and are still undergoing development in the DRP and IDER proceedings, the WG recommends that no actions be taken in this MUA proceeding until the outcomes of decisions under the CPUC's Distribution Resources Plan proceeding (R.14-08-013) and Integrated Distributed Energy Resources proceeding (R.14-10-003) are known.

CESA emphasizes that, while the DRP and IDER proceedings are the appropriate forums to establish metering, measurement, and settlement requirements for distribution services, there should be feedback loops between findings, observations, and recommendations from this WG with stakeholders in the DRP/IDER proceedings to ensure that any outcomes are mindful of multi-domain MUAs.

3.4 Assessment of the "Transmission" Domain

The classification for the implementation readiness of the services provided by BTM storage in the Transmission domain is either Category 2 or Category 3. The transmission deferral is under development in CAISO's stakeholder process for identifying Storage As a Transmission (SATA) resource. The certification and testing criteria for black start services are identified under the CAISO's Operating Procedure 5360.[15] The remaining transmission services are not currently in scope of any active initiatives, although the CAISO did initiate a stakeholder process—now in suspension—to consider development of a centralized market mechanism for primary frequency response.

Table 7: Transmission Domain: Implementation Readiness

Domain	Services	Implementation Readiness Category
Transmission	- Transmission deferral - Inertia - Primary frequency response - Voltage support - Blackstart	- Category 2 / In active development - Category 3 / Not in an active proceeding - Category 3 / Not in an active proceeding - Category 3 / Not in an active proceeding - Category 2 / In active development

4. Assessment of Prioritization of Services Based on Potential Revenue Streams

CESA provides in this section their perspective on the assessment of prioritization of services based on potential revenue streams.

For BTM systems, some revenue streams seem more relevant and available in the near-term. Further down the road, and pending outcomes and directions from other proceedings, additional 'revenue priorities' should be considered. Importantly, this MUA report should direct other proceedings to be mindful of MUAs.

1. RA (System, Local, Flex) payments: can be important revenue streams to finance storage technologies, as capacity payments are bankable and provide greater certainty of revenues for energy storage project development. RA payments may be a driving force to get existing and new projects to market in a timely fashion.

15 CAISO Operating Procedure 5360 http://www.caiso.com/Documents/5360.pdf

2. Transmission and distribution capacity deferral: payments also represent a high-potential revenue stream for energy storage resources on overloaded lines and circuits. Depending on the outcome of the IDER Pilot RFOs and a decision from the CPUC on the regulatory incentive mechanism (*i.e.*, 4% pre-tax incentive on DER service payments), BTM storage may also benefit from additional payments for deferral services.
3. Wholesale Energy and Ancillary Services payments are very important and beneficial to ratepayers who benefit from competition. Increased penetration of competing resources, including BTM ES, to the ancillary services markets would lower the future market price for these services. While the total addressable ancillary services markets are capped, this is a type of service that can be provided with high performance by energy storage resources, which are fast-responding and flexible across their charge/discharge range.

Recommendation 4: Dispatchable energy export should be considered for eligibility and compensation under DR

Status: Partial consensus

Olivine, Sunrun and other industry stakeholders recommend that dispatchable energy export should be considered for compensation under DR and that the policies, participation agreement (DRP-A) and models used for CAISO market participation should change to allow for such service. During one of the WG meetings, Demand Energy had indicated that they might prefer to get RA capacity payment through DR participation in the CAISO markets even if it means not getting NEM credits.
The IOUs think that the consideration of compensation for dispatchable export via DR must take into account revisions to the SGIP and NEM tariffs that may be necessary to bring the overall compensation and subsidies in line with the benefits provided (which would ensure there is no double-compensation).
In addition to consideration of SGIP and NEM construct changes, CAISO believes further deliverability studies from exports of DR must be evaluated to determine qualification of RA from the exported capacity. The CAISO notes that this issue would also apply to DERP-A for RA qualification.

5. Implication for the Seven BTM Energy Storage Use Cases of Implementation Readiness & Prioritization of Services Based on Potential Revenue Streams

With the MUA services at various stages of implementation readiness (cf. Section 3) and attractiveness in terms of revenue potential (cf. Section 4), the seven BTM ES use cases, which cover different combinations of these services, are therefore also at different stages of implementation readiness and attractiveness in terms of revenue potential. This section is focused on the seven use cases that were discussed by the WG, which does not preclude future uses cases from being identified and assessed at a later stage.

The use cases outlined below assumes the IOU is the procurer of grid services. Even though CCAs can procure RA and other wholesale grid services from energy storage providers, the WG did not discuss what the possible implications and gaps might be with these MUA rules since the CPUC has limited jurisdiction over CCA providers and whether the rules adopted for the IOU programs for ES MUA could translate to similar rules, models and configurations for CCA programs.

Use Case 1 was defined as "Load drop to the market, and providing RA to an IOU, as well as distribution level services to a DSO. NEM & Non-NEM. PDR"

This use case covers:

- 2 Reliability services:
  - Resource Adequacy (System, Local, Flex) provided through participation in DR (as PDR) is Category 1
  - Distribution Service is Category 2
- 2 Non-Reliability services:
  - Wholesale energy (load reduction using PDR[16]), via schedules or price/quantity offers during must offer obligation hours (MOO) to fulfill RA obligation, is Category 1.
  - Customer Retail Rate Management is Category 1, with NEM and non-NEM customers eligible to participate in DR.

Use Case 2 was defined as "Export to the market, providing RA to an IOU, as well as distribution level services to a DSO. NEM & Non-NEM. NGR"

This use case covers:

- 2 Reliability services:
  - NGR resources under DERP-A do not currently qualify for Resource Adequacy (System, Local, Flex) which is then classified as Category 3
  - Distribution Service is Category 2
- 2 Non-Reliability services:
  - Wholesale energy (normally a result of energy export to the grid from a battery discharge[17] using NGR) via schedules or price/quantity offers is Category 3
  - Customer Rate Management for non-NEM customers is Category 1. Retail rates still apply to all kWh even if they are scheduled and cleared through the CAISO wholesale energy markets for charging a battery and / or associated load.
  - NEM customers are not eligible to participate in DERP, unless explicitly allowed by the CPUC[18]. Customer Rate Management for NEM is therefore Category 3.

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16 Load Increase is currently under development (Category 2) in CAISO ESDER 3 and CPUC's LSWG. It could eventually be added to this use case.

17 In situations where over supply creates negative energy LMPs, participants may also receive a credit for consuming energy. In situations where Real Time LMPs are higher than Day-Ahead LMPs, participants may also receive credit for any cleared load decremental bid.

18 Approval to allow NEM customers to participate in the CAISO market via DERP-A will require CPUC to address issues such as double compensation, deliverability studies and counting procedures.

<u>Use Case 3 was defined as "Load drop to the market, providing RA to an IOU, as well as transmission level services to the ISO. NEM & Non-NEM. PDR"</u>

This use case covers:

- 2 Reliability services:
  - Resource Adequacy (System, Local, Flex) provided through participation in DR (as PDR) is Category 1
  - Transmission Service is Category 2
- 2 Non-Reliability services:
  - Wholesale energy (load reduction using PDR[19]), via schedules or price/quantity offers during must offer obligation hours (MOO) to fulfill RA obligation, is Category 1.
  - Customer Retail Rate Management is Category 1, with NEM and non-NEM customers eligible to participate in DR.

<u>Use Case 4 was defined as "Export to the market, providing RA to an IOU, as well as transmission level services to the ISO. NEM & Non-NEM. NGR"</u>

This use case covers:

- 2 Reliability services:
  - NGR resources under DERP-A do not currently qualify for Resource Adequacy (System, Local, Flex) which is then classified as Category 3
  - Transmission Service is Category 2
- 2 Non-Reliability services:
  - Wholesale energy (normally a result of energy export to the grid from a battery discharge[20] using NGR) via schedules or price/quantity offers is Category 3
  - Customer Rate Management for non-NEM customers is Category 1. Retail rates still apply to all kWh even if they are scheduled and cleared through the CAISO wholesale energy markets for charging a battery and / or associated load.
  - NEM customers are not eligible to participate in DERP, unless explicitly allowed by the CPUC [21]. Customer Rate Management for NEM is therefore Category 3.

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19 Load Increase is currently under development (Category 2) in CAISO ESDER 3 and CPUC's LSWG. It could eventually be added to this use case.

20 In situations where over supply creates negative energy LMPs, participants may also receive a credit for consuming energy. In situations where Real Time LMPs are higher than Day-Ahead LMPs, participants may also receive credit for any cleared load decremental bid.

21 Approval to allow NEM customers to participate in the CAISO market via DERP-A will require CPUC to address issues such as double compensation, deliverability studies and counting procedures.

<u>Use Case 5 was defined as "Distribution level service to the DSO and transmission level service to the ISO. NEM & Non-NEM"</u>

This use case covers:

- 2 Reliability services:
  - Distribution Service is Category 2
  - Transmission Service is Category 2
- 1 Non-Reliability services
  - Customers connected in the transmission domain cannot provide distribution services per rule 3. This use case therefore pertains to distribution-connected customers only.
  - Customer Rate Management (NEM / non-NEM) is Category 2

<u>Use Case 6 was defined as "Export or load drop to the market and distribution level services to the DSO. DERP, NGR & PDR"</u>

For greater clarity in the assessment of its implementation readiness, Use Case 6 is split hereafter in:

<u>Use Case 6a</u>: "Load drop to the market and distribution level services to the DSO. NEM & Non-NEM. PDR", which covers:

- 1 Reliability service:
  - Distribution Service is Category 2
- 2 Non-Reliability services:
  - Wholesale energy (load reduction using PDR[22]), via schedules or price/quantity offers, is Category 1.
  - Customer Retail Rate Management is Category 1, with NEM and non-NEM customers eligible to participate in DR.

<u>Use Case 6b</u>: "Export to the market and distribution level services to the DSO. NEM & Non-NEM. DERP & NGR", which covers:

- 1 Reliability service:
  - Distribution Service is Category 2
- 2 Non-Reliability services:
  - Wholesale energy (normally a result of energy export to the grid from a battery discharge[23] using NGR) via schedules or price/quantity offers is Category 3
  - Customer Rate Management for non-NEM customers is Category 1. Retail rates still apply to all kWh even if they are scheduled and cleared through the CAISO wholesale energy markets for charging a battery and / or associated load.

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22 Load Increase is currently under development (Category 2) in CAISO ESDER 3 and CPUC's LSWG. It could eventually be added to this use case.

23 In situations where over supply creates negative energy LMPs, participants may also receive a credit for consuming energy. In situations where Real Time LMPs are higher than Day-Ahead LMPs, participants may also receive credit for any cleared load decremental bid.

NEM customers are not eligible to participate in DERP, unless explicitly allowed by the CPUC.[24] Customer Rate Management for NEM is therefore Category 3.

Use Case 7 was defined as "Load drop to the market participating in both a utility DR program (BIP[25]) and a third-party DR program (DR Auction Mechanism). PDR"

During the March 5, 2018 WG meeting, Stem suggested the addition of a Use Case 7 where a retail customer would provide RA twice: once by participating in a retail DR program (BIP) for which the utility is the DR Provider, and a second time via DR Auction Mechanism (DRAM) for which a third-party is the DR Provider.[26] This use case would specifically require a capacity-differentiated MUA configuration. Within the confines of current CAISO and CPUC's dual participation rules, Use Case 7 cannot be implemented. Below is a non-exhaustive list of some underlying issues:

1. DR dual participation rules do not currently allow participation in multiple capacity-based programs.

CPUC rules only allow dual participation in one energy program and one capacity program, as well as one day-ahead program and one day-of program.[27] Dual participation rules were established for several reasons including avoiding double-payment and ensuring accurate baseline calculations.[28]

BIP is a day-of capacity (RA) program which would conflict with DRAM, which is also a capacity (RA) program, because the CPUC rules prohibit dual participation in more than one capacity program due to (1) potential double payment, (2) challenges with differentiating the same customer response for two different commitments and (3) determination of whether the grid received the benefit of two response, or only one.

In the DR proceeding, an Assigned Commissioner Ruling was issued on May 22, 2018 extending A. 17-01-012 to address some unresolved DR issues, including whether to revise DR dual participation rules.

2. Rule 24 dual participation rules do not allow third-party direct participation (DRAM in the example of Use Case 7) with a PG&E event-based DR program (BIP in the example of Use Case 7).

Rule 24 does not restrict the types of programs (energy or capacity, day ahead or day-of) that DRAM sellers enroll customers in, and neither Rule 24 nor the current DRAM purchase agreement requires third-party DR Providers to provide this information. This prevents the application of the DR dual participation rules.

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24 Approval to allow NEM customers to participate in the CAISO market via DERP-A will require CPUC to address issues such as double compensation, deliverability studies and counting procedures.

25 Stem further clarified that the Use Case 7 should not be interpreted as just BIP and DRAM participation, but to highlight the underlying issues stemming from a customer participating in two DR procurement mechanisms (DRAM and retail DR tariff).

26 Even though Use Case 7 is described as BIP and DRAM multi-use, the use case itself is not necessarily limited to these two DR programs.

27 D.12-04-045, p. 48

28 D.12-04-045, pp. 47-48

Even if third-party DR Providers were required to provide this information, the firewall[29] would limit the ability to utilize this information and enforce the protections against double-payment and proper accounting for baseline and load impacts from the dual participation rules. As a result, the IOUs have no mechanism to detect violations of the dual participation rules. The IOUs believe the inability to detect violations is the basis for the CPUC's explicit prohibitions within Rule 24.

The only way to mitigate these problems relating to dual participation is a whole reassessment of Rule 24 and DRAM, through a robust stakeholder process where stakeholders would have the opportunity to discuss how to mitigate dual participation, which would require new restrictions on which programs can be offered (any combination of energy or capacity, day-ahead or day-of). IOUs would need to know when each DRAM customer is dispatched, and DRAM sellers would need to incorporate the IOU's dispatches into their baseline calculations, which would effectively eliminate the firewall designed to protect third-party DR Providers. There would be new processes and systems to be put in place, with the potential request from IOUs for associated cost recovery.

In the DR proceeding, an Assigned Commissioner Ruling was issued on May 22, 2018 extending A. 17-01-012 to address some unresolved DR issues, including the evaluation of DRAM to further develop the record on its potential future design.

3. The CAISO rules currently prohibit more than one DRP from registering a customer location.

CAISO clarified that one cannot have the same service account participate with 2 different DRPs (though one can have 2 different resources at the same location, identified by the retail service account). As BIP has been integrated into the CAISO wholesale market as a RDRR as of May 1, 2017, customer locations may not be in both the IOU's resource and a third-party DRP's resource at the same time. Thus, dual participation is not permitted between DRAM and BIP.

To lift this barrier, CAISO would need policy and systems enhancements to allow one single resource (identified by its retail service account) to participate with different DRPs.

Table 8: Use Case: Summary Table

	Use Cases	Reliability Services			Non-Reliability Services		Counts
		Resource Adequacy	Distribution	Transmission	Wholesale	Customer Self-Services	
Use Cases with DR participation as PDR	Use Case 1	Category 1	Category 2	X	Category 1	Category 1	Category 1: 3 Category 2: 1 Category 3: 0
	Use Case 3	Category 1	X	Category 2	Category 1	Category 1	Category 1: 3 Category 2: 1 Category 3: 0

29 Among many things, Rule 24 establishes protection and a firewall so that utility's employees who manage Utility DR programs do not know which customers are participating in a DRAM seller's DR program and when they are being bid or cleared in the CAISO markets.

	Use Case 6a	X	Category 2	X	Category 1	Category 1	Category 1: 2 Category 2: 1 Category 3: 0
	Use Case 7	Category 2	X	X	Category 2	Category 1	Category 1: 1 Category 2: 2 Category 3: 0
Use Cases with DERP participation as NGR	**Use Case 2**	Category 3	Category 2	X	Category 3	NEM: Cat 3 Non-NEM: Cat 1	Category 1: 1 Category 2: 1 Category 3: 3
	Use Case 4	Category 3	X	Category 2	Category 3	NEM: Cat 3 Non-NEM: Cat 1	Category 1: 1 Category 2: 1 Category 3: 3
	Use Case 6b	X	Category 2	X	Category 3	NEM: Cat 3 Non-NEM: Cat 1	Category 1: 1 Category 2: 1 Category 3: 2
No CAISO participation	**Use Case 5**	X	Category 2	Category 2	X	Category 2	Category 1: 1 Category 2: 2 Category 3: 0

6. Recommendations for Metering, Measurement, and Performance Settlement

All seven use cases have areas that require additional regulatory work and are all in different stages of implementation readiness.

6.1 Metering, Measurement and Settlement Rules for the Services in Use Cases 1, 3, 6a and 7 with DR participation as PDR

6.1.1 Customer services

All identified customer services use the following methods:

a. Metering:
   CPUC-approved revenue meter is placed at the customer's premise.
b. Measurement:
   Revenue meter is used to recognize the energy and demand of the premise.
c. Settlements:
   (Retail usage from revenue metering) x (applicable retail rate schedule)

6.1.2 Resource Adequacy provided through participation in Demand Response

At the April 20, 2018 meeting, the WG discussed whether the CPUC needs to approve CAISO's MGO (CAISO ESDER 1) and new alternative baselines proposed by CAISO in ESDER 2.

PG&E stated that if the methods of wholesale energy measurement (baselines) and sub-metering (MGO) are used to measure the performance and payment of resource adequacy, then the CAISO's MGO and new alternative baselines should be first adopted by the CPUC for purposes of retail settlements. More specifically:

- RA settlement requires the CAISO's adoption of the retail capacity baseline, which is under the CPUC's jurisdiction.
- Retail capacity baseline is based on the retail energy baseline, which can be similar or different from the wholesale energy baseline, depending on CPUC's rules.
- Wholesale energy baselines, including CAISO's MGO and the proposed ESDER Phase 2 alternative baselines, if used to calculate the retail energy baseline to then determine the retail capacity baseline for RA payment, should be adopted by the CPUC before any party, including the IOUs, can utilize such mechanism.
- The topic of baselines is important especially with new resource participants (i.e., residential customers and small medium business) enrolling in DR. DR 2018-2022 Decision (D.17-12-003) recognizes this and stated the following to address this issue:
  This Decision determines that the Commission will address the issue of baselines once the FERC approves the wholesale baselines for the CAISO. Given the complexity that PG&E cautions the Commission about, the issue of baseline is one that may require additional evidence.
- CAISO's MGO adopts a sub-meter configuration and requires further discussion as current DR settlement and metering configuration is done at the entire premise-level and not at the device/technology level. This is a fundamental shift from current DR practice.
  - During the March 5, 2018 WG meeting, Tesla suggested using the internal energy storage device metering for MUA context in lieu of a CAISO meter, or a utility-grade meter. The discussion however did not go on any further and no formal recommendation was developed.
- In addition to a decision from the CPUC, additional system enhancements or additional build out would be required to accommodate the utilization of MGO and alternative baselines as part of ESDER Phase 2. PG&E, during the March 5, 2018 WG meeting, provided a non-exhaustive list of open issues like cost recovery, metering enhancements, billing, etc., which will require further assessments and identification of the exact proceedings in which these issues should be addressed. PG&E's slide is copied hereafter.

Table 9: Open Sub-Metering Issues

Metering
Open Issues (2/2)

Retail (CPUC's jurisdiction)	Wholesale DRP-A (CAISO's jurisdiction)
» **One retail meter** at the **whole premise level**	
» *CPUC's rules TBD*	» CAISO **MGO** models

Development of CPUC's rules to be associated with CAISO's MGO configuration Model B	
Open Issue	**Proposed Forum(s) for Resolution**
Requirements for the sub-meter equipment • Rules and responsibilities for the sub-meter equipment • Sub-meter data accuracy requirements • Certification of the sub-meter	• Demand Response Proceeding? General Rate Case?
Requirements for the sub-metered data • Rules and responsibilities for for data collection, vetting / VEE to applicable standards, storage • Coordination, management and processing of sub-metered data	• General Rate Case?
Primary retail meter and Sub-meter interactions • Reconciliation of meter data management between the sub-meter and the whole meter premise for billing and settlement purposes	• General Rate Case?
Enhancements to Utility's systems • Enhancements to billing and other utility systems to provide a new Service Agreement / UUID to tag each BTM storage (and possibly other BTM devices in the future) so that it can be enrolled in CAISO's Demand Response Registration System (DRRS).	• General Rate Case? Electric Rule 24?
Cost Recovery • Identification of all related costs to the item listed above • Determination of who will bear the costs of direct metering initial implementation • Determination of who will bear the costs of direct metering Operations & Maintenance	• General Rate Case?

Recommendation 5: IOUs' recommendation with CAISO and Olivine support: Address Open Metering Issues Prior to Settling MGO or New ESDER 2 Baselines for RA
Status: Partial consensus

The IOUs, with support from CAISO, and Olivine agree that if the MGO or new ESDER 2 alternative baselines are used to settle for resource adequacy, the CPUC should address the issues listed above and provide a ruling before this new configuration can be used for retail settlement purposes.

Some industry stakeholders recognize the recommendation put forth by the IOUs and emphasize that, if the Commission determines they need to approve these meters (under CAISO's SCME configuration), a sense of urgency needs to be applied to resolve this as soon as possible since MGO is already FERC approved and CAISO implemented.

In its comments to this report on May 21, 2018, CESA disagrees that the CPUC approval is needed for BTM storage to utilize MGO or any other CAISO new baseline methods for the purpose of retail settlement. CESA believes that Scheduling Coordinators Metered Entities can provide sufficient oversight and auditing over submetering without needing CPUC approval.

There are many ways to measure Resource Adequacy capacity based on the tariff program (Capacity Bidding Program (CBP)) and contract rules (DRAM Pilot). Below is a comparison of metering, measurement and settlement for RA between CBP (a retail program administered and operated by an IOU) and a third-party DR program via a DRAM contract:

a. Metering:
   CPUC-approved revenue metering, placed at the customer's premise, is the primary data recorder for the entire service account or service agreement.
b. Measurement:
   - Retail CBP allows participants to nominate their available capacity month to month:
     - If there are no dispatched events, the nominated capacity (kW) is assumed delivered.
     - If there are dispatched events for the month, the retail energy (kWh) baseline will determine if the capacity nominated by third-party participant is met.
   - Under DRAM, third-party participants, based on their awarded contract quantity, are given three options to show that they provided the capacity.
     - If there are CAISO dispatched events during the CAISO's Availability Assessment Hours, the wholesale energy baseline will determine if the RA capacity under the DRAM contract was provided by the seller. If there are multiple events, participants can use the highest performing hour for compensation.
     - If there was no test event or dispatch, capacity is determined based on bid-in availability during the CAISO's Availability Assessment Hours.
     - Seller provides evidence to the buyer (IOU) that the contracted capacity was bid into the CAISO markets.
c. Settlements:
   - CBP is settled using the following method:
     - If there are no CAISO dispatched events: (nominated capacity) x (monthly capacity price)
     - If there are CAISO dispatched events: each event hour for a given month is treated separately. The retail energy baseline will be calculated by the IOU and is used to determine the hourly performance of the participating resource. Hourly performance (%) will determine the capacity incentive based on the CBP's current tier incentives.
   - DRAM's RA performance is calculated by the seller using the following settlement method:
     - A = Contract Price for the month
     - B = The lesser of (i) the Demonstrated Capacity for each type of Product for the applicable Showing Month, and (ii) the corresponding Product Monthly Quantity for the applicable Showing Month.
     - C = 1.0 if Seller has chosen (i) not to deliver Residential Customer Product in Section 1.1(c), or (ii) to deliver Residential Customer Product in Section 1.1(c) and the Product delivered meets the definition of Residential Customer Product;

or 0.90 if the Product delivered does not meet the definition of Residential Customer Product.

- D = (i) 1.0 if Seller has chosen to deliver RDRR in Section 1.1(e); or (ii) if Seller has chosen to deliver PDR in Section 1.1(e), the percentage of Product delivered that is PDR.
- Delivered Capacity Payment = [A x B x C x D].

Recommendation 6: PG&E and SDG&E Recommends the CPUC Further Investigate Separating Capacity Measurement from Energy Measurement

Status: Consensus

During the March 5, 2018 WG meeting, PG&E raised several questions on whether separating capacity measurement calculation from energy measurement should be considered by the WG and the CPUC.

- Should retail capacity measurement be different moving forward, recognizing that there are other services that will be served?
- Does it make sense to have capacity and energy measured separately?
- Should measurement be different for distribution services than for capacity or energy?
- Currently, look at energy values to see if capacity delivery has been met – will additional requirements be needed?

Various MUA WG participants expressed interest to explore these questions further. In its comments to this report on May 21, 2018, Stem and Sunrun supports further exploration and recommends addressing this topic as part of either the CPUC's DR proceeding or RA proceeding.

PG&E and SDG&E recommends that this topic be addressed in a CPUC proceeding that would evaluate the values of a uniform capacity measurement methodology approach that can be utilized to determine all capacity services (i.e., resource adequacy, distribution deferral, etc.).

6.1.3 Wholesale – Energy and Ancillary Service (Spinning / non-Spinning) through participation in DR

a. Metering:

CAISO has defined two metering entities: Independent System Operator Metering Entity (ISOME) or Scheduling Coordinator Metered Entity (SCME). The metering entities have different functions and approved metering equipment to track a resource's usage and flow. PDR and RDRR only use SCME configuration.

- SCME – the scheduling coordinator polls the meters, performs the validation, estimation and editing (VEE) and submits the resulting settlement quality meter data (SQMD) to the CAISO. This entity is required to adhere to the requirements of the Local Regulatory Authority (LRA), e.g., the CPUC. In the case of the utilities, the CPUC has jurisdiction over approval of metering equipment, rules on error rate, VEE process, etc. In the absence of LRA requirements, the SCME must adhere to CAISO technical metering and VEE requirements prescribed in the CAISO's BPM for metering.

- SCs have an agreement with the CAISO and are held to audit requirements to ensure that they are providing accurate SQMD data. Audit is a yearly attestation that they are following the rules for SCMEs. SCME was created originally to facilitate demand response.
- As part of Energy Storage Distributed Energy Resource (ESDER) Phase 1, the CAISO designed and filed a metering configuration that allows for sub-metering which was approved by the FERC; MGO. CAISO's MGO has three options and within the same aggregation, different configurations at each site is permissible:
  - Load reduction only – load baseline is established using a derived meter value (Net meter – Generator meter).
  - Generation offset only – performance is attributed to response of a generation device.
  - Load reduction and generation offset – response of the load and generation device can be measured separately and combined.

b. Measurement:

CAISO accepts the following energy measurement (baseline) methodology:

- 10-10 baseline with morning adjustment (+/- 20%).
- The CAISO is in the process of filing ESDER Phase 2 new baselines methodology to the FERC. The proposal will cover the following baseline methods:
  - Control Group
  - 5-10 baseline
  - Weather Matching
- For ancillary services (spinning and non-spinning reserve) the CAISO requires the third-party provider and their Scheduling Coordinator to submit retail revenue meter data (kW and kWh) for the awarded intervals. The CAISO requires before, during and after meter data for the awarded intervals to evaluate whether the PDR resource has sufficient capacity.

c. Settlements:

CAISO settles energy by taking the PDR resource performance (coming from the baseline – meter usage = performance) and settling based on which market the PDR resource was cleared and awarded. If the PDR resource was awarded in the day ahead market, it would be the awarded quantity (MW) x the cleared day-ahead Locational Marginal Price (LMP). If the PDR resource does not adjust their schedule, by bidding in real time market, the meter usage flow for the awarded intervals will be settled by multiplying by the real time LMP. Any deviations from the day-ahead awarded schedule would be classified as uninstructed imbalance energy (UIE).

For ancillary services (spinning and non-spinning), the CAISO will evaluate the meter before, during and after to assess if enough capacity was reserved during the awarded intervals. If the ancillary service is dispatched by the CAISO, it would utilize the wholesale energy baseline to measure if the PDR resource was able to perform and deliver the instructions. Ancillary services are dispatched in real time and would be settled by using the real time LMP multiplied by the performance.

6.1.4 Distribution and Transmission Services

As previously identified, there are no current rules or methodologies for BTM storage providing Distribution and Transmission services. The WG recommends the CPUC manage the development of uniform metering, measurement and settlements for Distribution services provided by Energy Storage within the DRP and IDER proceedings.

The WG defers to the CAISO on the development of SATA and the associated metering, measurement and settlements requirements for BTM. The current SATA stakeholder forum is assessing the extent to which cost recovery for storage devices providing transmission services will be subject to the device's market performance during times when the device is not needed for the transmission service. It is also assessing whether CAISO control of the storage device during times when the device is needed for transmission service, will unduly compromise the CAISO's market independence. Given this, the WG recommends that consideration of MUA applications involving SATA, be deferred until completion of the CAISO's SATA stakeholder process.

6.2 Overlay of the 3 MUA differentiation categories to Use Cases 1, 3, 6a and 7.

6.2.1 Simultaneous MUA:

CESA stated, simultaneous MUAs create unique challenges for metering, particularly when the aggregate 'response' of a resource is inadequate to meet the combined schedules, e.g. a distribution schedule and an energy schedule. In cases where the combined schedule is not met, the settlement process may require a 'protocol' or 'priority' for assigning the deviation. For instance, is the deviation assigned to the 'less important' service? While CPUC MUA rules direct that resources should only pursue MUA service-combinations that are doable, there may still be instances where services are under-delivered, similar to when a distribution line goes down and 'fails' in providing distribution service. Rules should continue to safeguard against cases where reliability services are willfully disregarded by MUAs, though contract rules for such services may suffice to direct performance appropriately. Solutions may include grid service commitments, either through contract/tariff provision, special contracts, or just the existing rules. Concerns exist about the challenge of tracking permutations that could be burdensome to utilities or planners.

Given the challenges simultaneous MUA configuration has, the WG did not explore what metering, measurement and settlement requirements may eventually be needed to enable such a configuration.

6.2.2 Time Differentiated:

CAISO stated in the April 5, 2018 WG meeting that RA has either a yearly or monthly commitment based on what the resource provider sold to the buyer. Therefore, based on the current RA construct and the commitment levels needed from the resource, weekly and daily time differentiated is not feasible. Distribution RFOs could be a seasonal or month-to-month commitment. The WG agreed that such time differentiated – weekly and daily use cases may not be doable today but reserve the right to re-considerer for future application on a case-by-case basis.

6.2.3 Capacity Differentiated:

WG discussed limited scenarios of what a capacity differentiated metering, measurement and settlement for BTM would require. The WG agreed that metering alone would not solve the challenge of enabling capacity differentiation. Additional tools like software may be required to distinctly split the resource. However, the WG did not explore the requirement of this additional software tool.

6.3 Metering, Measurement and Settlement Rules for Use Cases 2, 4, 5 and 6b with DERP participation as NGR

6.3.1 Wholesale – Energy and Ancillary Service through participation in DERP-A

a. Metering:
CAISO has defined two metering entities; ISOME or SCME. The metering entities have different functions and approved metering equipment that can be used to track a resource's usage and flow.

- ISOME – CAISO directly polls the meters and the ISO performs the VEE to produce SQMD. Minimum is 500 kW. For participants that wish to use ISOME, the CAISO assumes that the resource will always be participating in the CAISO market; 24 x 7 – 365 days.
    - SCME – the scheduling coordinator polls the meters, performs the validation, estimation and editing and submits the resulting SQMD to the CAISO. This entity is required to adhere to the requirements of the LRA, e.g., the CPUC. In the case of the utilities, the CPUC has jurisdiction over approval of metering equipment, rules on error rate, VEE process, etc. In the absence of LRA requirements, the SCME must adhere to CAISO technical metering and VEE requirements prescribed in the CAISO's BPM for metering.
    - SCs have an agreement with the CAISO and are held to audit requirements to ensure that they are providing accurate SQMD data. Audit is a yearly attestation that they are following the rules for SCMEs. Although SCME was created originally to facilitate demand response, the CAISO has made the allowance that DERP-A using NGR or PG can also utilize SCME.

b. Measurement:

CAISO accepts direct metering configuration and does not utilize a baseline to measure the performance of the NGR or PG resource.

  - Third-parties are to put a self-schedule (price taker) and/or energy bid in the CAISO's day ahead market. The schedule and/or awarded amount minus the direct meter output is used to evaluate the performance of the resource.

For ancillary services, the CAISO requires the ISOME or SCME via, Scheduling Coordinator, to submit settlement quality revenue meter data (kW and kWh) for all intervals (24 x 7). The CAISO requires before, during and after meter data for the awarded intervals to evaluate whether the NGR or PG resource has sufficient capacity.

c. Settlement:

CAISO settles energy by taking the NGR or PG resource performance (coming from the schedule and/or awarded amount – meter usage = performance) and settling based on which market the NGR or PG resource was cleared and awarded. If the NGR or PG resource was awarded in the day ahead market, it would be the awarded quantity (MW) x the cleared day-ahead Locational Marginal Price (LMP). If the NGR or PG resource does not adjust their schedule, by bidding in real time market, the meter usage flow for the awarded intervals will be settled by multiplying by the real time LMP. Any deviations from the day-ahead awarded schedule would be classified as uninstructed imbalance energy (UIE).

For ancillary services, the CAISO will evaluate the meter before, during and after to assess if enough capacity was reserved during the awarded intervals based on the cleared schedule. If the ancillary service is dispatched by the CAISO, it would calculate the resource performance (schedule and/or awarded amount – meter usage = performance) and determine if the resource was able to perform and deliver the instructions. Ancillary services are dispatched in real time and would be settled by using the real time LMP multiplied by the performance.

Given that under a DERP-A, using either NGR or PG model, direct metering without baseline is the accepted metering configuration to measure and settle the resource, it will be challenging to identify the incrementality provided by the resource.

The WG did not fully discuss this and the topic therefore requires additional dialogue. It is PG&E's opinion, that some form of *baseline* is needed if the energy storage is providing additional services to a different buyer or grid operator. Without *baseline,* the energy resource provider and the buyer of services will require some form of agreement(s), process and/or acknowledgement on how to partition the direct meter usage data to calculate the settlements. This is especially true, when the energy storage resource, single site or aggregation, has overlapping dispatch instructions.

7. Additional topics that require further discussion

Several topics were briefly raised during the WG meetings or in comments to this paper, but due to limited time, they were not fleshed out. Below is a non-exhaustive list of such topics:

- Centralized Meter Data Management Agent (MDMA) – The concept was introduced by the CAISO to address the need for consistent revenue and settlement quality meter data and management, for those resources providing multi-use application services, to avoid any inconsistencies in measurement of services attributed to each domain and avoid any double payment for them.

- Telemetry requirements – The CAISO has existing telemetry requirements based on the size of the resource and the type of grid services being offered (ancillary services). Visibility requirements for providing other services (i.e., distribution, transmission) are addressed in active proceeding and stakeholder forum.

- Systems (Registration) – In order to enforce and track all customers' MUA activities, PG&E suggests considering a system that records all customers' chosen MUA configuration in order to assist buyers of grid services the ability to recognize an individual customer's capabilities.

- Load shift product as a distribution service – Sunrun identified the service of increasing load to maintain distribution level reliability. The Load Shift product at the CAISO can be categorized under the wholesale energy imbalance service. But at the distribution level Sunrun contends that it can be a variation of "capacity" deferral service when coordinated with the DSO.

- Aggregated resource metering requirement – When providing any of the three MUA configurations, additional metering configuration may be necessary to observe and calculate the performance of an aggregated resource.

- Given the transition of IOUs' load to CCAs' portfolios, further discussion is needed to identify what this development means to the overall application of the MUA rules, specifically the involvement of CCAs, versus the IOU's LSE and UDC. Incorporating in the information on when and what the CPUC might require, and what would and would not be enforceable, vis a vis CCAs and access to/use of their customers, would be invaluable.

Multiple Use Applications for Energy Storage Working Group Chapter 2. Metering, Measurement and Settlement for In Front of the Utility Meter Storage Resources	
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1. Synopsis

This section reflects discussions that took place at the March 13, 2018 meeting of the Multiple Use Applications (MUA) for Energy Storage (ES) Working Group (WG) as well as feedback that was obtained during the drafting of this report section.

1.1 This section addresses the following issues:

- Appropriate metering and measurement arrangements for in-front-of-the-meter storage (IFM) resource(s) providing multiple services (1) at different times ("time-differentiated MUAs"), (2) at the same time but using different sources of capacity ("capacity-differentiated MUAs"), and (3) at the same time using the same sources of capacity ("simultaneous MUAs").[30]

1.2 The MUA ES WG participants agree on the following:

- Adequate measurement of IFM energy storage is required for UDC and CAISO operational visibility, performance verification and settlement functions. This typically includes physical metering and telemetry.

- For IFM MUAs, metering and sub-metering arrangements[31] described by the CAISO in the ESDER initiative are sufficient to measure IFM's performance in time-differentiated, capacity-differentiated, and simultaneous MUAs. While measurement may be facile, settlements can be unclear, especially in cases where the resource shows a deviation from its MUA schedules. In this case, somewhat standardized practices that direct a deviation to one MUA service versus another, or that allocate the deviation among the services, may be useful.

30 The CPUC Energy Division staff member leading the discussion deferred settlement arrangements to a later working group meeting.

31 Sub-metering generally is required to capture station power use. However, depending on the specific configuration of station power devices, sub-metering may not capture all station power use billable at retail. For example, sub-metering would typically not capture step-down transformer losses and other energy consumption during fifteen-minute intervals when the storage device is simply maintaining its State of Charge (SOC), i.e., when the device is "idling." In lieu of sub-metering, station power use could simply be estimated as a static or variable percentage of overall load.

- Utilities and IFM energy storage providers agree that, in accordance with station power netting rules, UDCs may bill at retail for station power loads. Further, there is agreement that measurement requirements for station power loads must be developed. There is an array of solutions, including metering and estimation, that can be considered -- requiring physical metering solutions for all station power loads is impractical in some cases and impossible in others.

- In some cases, 'outsourcing' of performance measurement, as is done through the CAISO's Scheduling Coordinator Metered Entity (SCME) mechanism, may be useful. The SCME mechanism may be especially useful for smaller project types where sophisticated physical metering is cost-prohibitive.

- UDC and IFM storage provider will need to agree on an estimation methodology on a case-by-case basis in instances where it is prohibitively costly, impractical, or impossible to determine retail load through direct metering.

- The WG agrees that in a multi-use setting for IFM ES, it is necessary to account for the difference between measured charge/discharge quantities and dispatched quantities. SDG&E believes the most practical way to account for this difference and ensure all entities are treated fairly, is to incorporate appropriate settlement provisions in the contracts under which the IFM ES provides reliability services to the DSO and/or CAISO.

Recommendation 1: CPUC Should Give UDCs Ability to Require IFM ES Providers to Grant UDC Access to CAISO Energy and Ancillary Service Schedules

- Require IFM energy storage providers to authorize the UDC to obtain day-ahead and real-time schedule information from the CAISO. In order for this schedule information to be useful to the UDC, it needs to be available with enough lead time to allow the UDC to respond effectively.

Recommendation 2: CPUC Should Give UDCs Ability to Require IFM ES Providers to Submit Meter Data Plan for UDC Approval

- To ensure adequate measurement for IFM storage resources supplying wholesale and distribution services, the owner of the IFM storage resource would be required to submit, for both CAISO and UDC review and approval, a settlement quality meter data plan that describes in detail the metering configurations as well as the measurement plan to account for multiple services, and station power loads for the IFM storage resource.

2. Metering and Measurement of IFM ES Participating in Multiple Services

2.1 Issue Statement

When an IFM energy storage resource provides multiple services, and receives compensation from more than one entity, there needs to be measurement mechanisms that provide information sufficient to (i) establish whether, and the extent to which, each service was provided, (ii) in accordance with CPUC rules, account for all energy, including station power loads, to be settled at retail, and (iii) in accordance with the CAISO tariff, account for all energy to be settled at wholesale.

A key area of ambiguity and contention is around the treatment of charging for IFM energy storage providing distribution services. The CPUC has not yet made a determination on this matter as the IDER proceeding has yet to consider this specific issue. CESA believes that IFM energy storage never provides retail service, though station power loads should be billed as retail load. Specifically, CESA views an IFM storage resource providing distribution services would be treated as losses or, at minimum, settled as wholesale energy. However, in SDG&E's view, an IFM storage resource that provides distribution deferral services is clearly providing a retail service. On this issue, the question arises as to whether the energy used to charge and discharge the IFM storage device in performance of the distribution deferral service would be settled at retail rates or wholesale rates.[32]

An issue raised by energy storage providers during the March 13, 2018 working group meeting is the degree of measurement accuracy needed to capture the provision of individual services, as well as for station power consumption.

2.2 Proposed Solution(s) for Services

Sufficient metering, telemetry or in some cases estimation, is important to support incrementality determinations, validate resource performance and perform financial settlements. The nature of the metering and telemetry that is necessary, is determined by the degree of accuracy which is reasonable.

Adequate metering and telemetry of IFM energy storage is required for UDC and CAISO operational visibility and for performance verification as well as accurately determining retail loads. Utilities and IFM energy storage providers will, on a case-by-case basis, negotiate estimation methodologies and agree on UDC measurement requirements for station power loads. The working group discussed some factors that may help derive acceptable measurement arrangements for IFM energy storage resources: size of retail and station power loads, implementation costs and ongoing costs, complexity of measuring and viability of alternatives.

Sub-metering is required to settle wholesale and retail services and to account for station power use (including the 15-minute netting of station power use against any charging or discharging within the

[32] SDG&E sees distribution deferral service as a "retail" service in as much as retail customers will pay for that service through distribution rates regulated by the CPUC. Some stakeholders characterize distribution deferral service simply as a "distribution service."

same interval.[33]) UDCs will consider the use of estimation techniques where the implementation costs and/or ongoing costs of sub-metering are unusually high.

IFM energy storage resources may rely on a third-party Scheduling Coordinator who is responsible for polling the meters and performing the data validation, estimation and editing (VEE).[34] The Scheduling Coordinator will submit the resulting settlement data for each settlement period to the CAISO and 15-minute daily interval data to be submitted and reconciled monthly with the UDC.[35] [36]

Parties expressed varying views on the need for accurate measurement. SDG&E indicated that, for distribution operation purposes, the UDC seeks telemetry showing the real-time level of charging/discharging of IFM energy storage resources. SDG&E notes that, for revenue purposes, telemetered data typically used for operational visibility and generally lower in quality than revenue metering, but, if cumulated at the appropriate time intervals and stored, can be used to measure performance and to settle. The least accurate approach is to estimate production and consumption through off-line processes. Revenue-grade time-stamping meters provide the highest quality measurement of IFM energy storage resource(s) activities and is the preferred method for measuring performance and retail energy quantities. Each of these approaches has distinct costs that should factor into determining when each approach is appropriate in which use cases and configurations.

PG&E agrees that the use of revenue grade meters is preferred, but notes that there may be instances where even with time-stamping revenue metering, accurate determination of retail quantities may be challenging. PG&E recommends there be a placeholder in the tariff for estimation at the UDC'S discretion.

SDG&E noted that its experience with "estimating" consumption and production data for settlement purposes, is that the cost of setting up the necessary systems can exceed the cost of a system that uses revenue-grade meters. However, PG&E observed that for large installations (e.g., 10MW+), estimation could be a more cost-effective and process-effective than creating new retail service settlement systems.

SDG&E's position is that IFM storage devices need to install telemetry capability and revenue-grade meters to measure charging and discharging energy. Revenue grade metering helps to ensure accurate billing and payments and will reduce the possibility of settlement disputes. Where distinct services are being provided to the UDC and the CAISO within common settlement intervals, the contract between the UDC and the IFM storage resource may need to specify a netting function so that both parties realize the cost and benefits contemplated by the contract. The CAISO may lack visibility to distribution-connected IFM storage resources that participate in wholesale markets. The CAISO has telemetry

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33 PG&E and SDG&E both confirmed that storage projects online now are netting at wholesale. Upon follow-up, CPUC ED learned that SCE's projects are also netting at wholesale. PG&E explained that its process is manual process for now, pending IT system upgrades. PG&E will work with folks on estimation.

34 The CAISO provides two methods for collecting and reporting meter data: an ISO Metered Entity (ISOME) and a Scheduling Coordinator Meter Entity (SCME). The CAISO directly reads the meters of ISOMEs and performs the VEE. Alternatively, an SCME performs these functions and submits the final settlement quality meter data to the CAISO for settlement. SCMEs traditionally were load resources; however, the CAISO recently expanded the SCME option to permit supply resources to come in and out of the market, and do other things, such as MUA.

35 The CAISO noted that the UDCs could adopt a data collection/reporting structure similar to the CAISO's SCME or ISOME. These entities would take on meter data responsibilities, such as collecting and reporting station power consumption, that would otherwise have to be managed by the UDC.

36 The CAISO tariff currently provides a 5-minute netting interval. The IOU tariffs provide a 15-minute interval.

requirements that provides for visibility to the participating resources, when greater than 10 MWs or in the provision of Ancillary Services but would not necessarily have visibility to the surrounding distribution grid conditions which may limit that resource from participating and affect the resources capacity deliverability. Whereas the CAISO schedules and dispatches resources to balance supply and demand and manages constraints on the transmission system with full visibility, the CAISO generally lacks visibility into the utilities' distribution systems and dispatches DERs without knowing the specific impact those dispatches have on the utilities' distribution systems (and the loads and resources connected to the distribution systems).

It is the responsibility of the IFM storage owner to respond to CAISO dispatch instructions. Distribution-system outages or operational limitations resulting from distribution system safety and reliability considerations can create challenges for the delivery of wholesale services from distribution-connected resources. The CAISO's existing Outage Management System can be used by the IFM storage owner's Scheduling Coordinator to inform the market optimization process if distribution system constraints will limit distribution-connected IFM storage operations or availability.[37]

Currently, distribution utilities do not have the same level of visibility, control and situational awareness of DERs as the ISO does for transmission-connected generators. Distribution utilities have grid modernization efforts underway to increase the granularity of their visibility on the distribution grid, as well as with DERs operational performance. These challenges will only increase with increasing numbers of DERs aiming to provide multiple services to different entities.

With respect to distribution-connected IFM storage resources, it is anticipated that the distribution utility will have visibility of, and a contractual relationship with, the IFM storage resource sufficient to avoid creating issues on the distribution system. This contractual relationship can involve communication between the UDC and asset owner or designee (such as an aggregator or scheduling coordinator) on known distribution system constraints. Scheduling Coordinators for such distribution-connected IFM storage resources can reflect known or potential distribution system constraints in the IFM storage resource's market participation schedules or in its price/quantity offers/bids into CAISO markets.

Multiple communication paths can be, or have been established for distribution-connected IFM storage resources engaged in MUAs. Not only does the CAISO communicate with participating resources (or their designees), but participating resources may also relay information to the UDC where appropriate. Such information assists the UDC in maintaining safe and reliable distribution operations as real-time conditions develop. Revenue grade smart meters will also ensure the UDC has the necessary visibility onto the distribution system. At the workshop, the CAISO noted that, with the storage owners consent, charge/discharge schedules awarded through the CAISO's day-ahead and real-time markets are available to third parties. Thus, the UDC should be able to obtain day-ahead schedule information.

Because the CAISO's real-time market can result in changes to an IFM storage resource's day-ahead schedule, UDCs may have an interest in knowing the resulting schedule changes prior to actual real-time operation. It is unclear if, or how, these schedule changes can be communicated to the UDC sufficiently in advance of actual operations for the UDC to take any action. LS Power pointed out that the UDCs don't see the CAISO's Automatic Generation Control (AGC) signals sent to a third-party owned IFM

[37] PG&E has direct experience incorporating distribution limitations in the day-ahead offer/bids PG&E submits to the CAISO for the Vaca Dixon and Yerba Buena storage projects (as part of the interconnection agreements for those resources). PG&E uses the CAISO Outage Management System to insert storage project derates to ensure the storage projects are not scheduled for more than the limitation allows.

storage device and therefore would not have real-time visibility of regulation services. CAISO noted, though, that the regulation award would be visible after operation of the day-ahead market, well in advance of real-time dispatch.

2.2.1 Time Differentiated MUA

When multiple services are being provided at different times with sufficient separation between settlement periods, e.g., in different months, no significant settlement issues were identified, with the assumption that there are provisions for non-24 x 7 participation requirement and settlement in the wholesale markets. Under this construct, when not providing wholesale market services (e.g., providing only distribution level services), there would be no CAISO settlement and no meter data submission requirement by the CAISO as an SC metered entity, a requirement for MUA participating resources. When providing wholesale services, the CAISO settles both the charging and discharging energy of a non-generating resource at the wholesale LMP. The CAISO stated that for metering services provided by a Scheduling Coordinator Metered Entity (SCME), it is unlikely that a separate CAISO meter would be required apart from the Distribution System Operator (DSO) revenue quality meter. The CAISO anticipates that the vast majority of, if not all, IFM storage resources will be utilizing the SCME option for CAISO settlement when providing multi-use services.

A typical construct is that an IFM storage resource providing distribution service gets a contract with the UDC and payment is based on capacity. The UDC will determine whether the storage device charged and discharged during the examined period and, if it did, the IFM resource will receive a capacity payment.

It was suggested that the CAISO's outage management system (OMS) can be used to "remove" an entity from the wholesale market. However, questions were raised as to whether the use of the OMS will actually achieve the intended effect. For example, a IFM energy storage resource providing a distribution service may use the OMS to limit the CAISO from directly dispatching the resource but any subsequent charging and/or discharging energy to provide a distribution service will still be settled as uninstructed energy by the CAISO. So, while the use of the OMS may be helpful for the CAISO's daily planning purposes, it does not appear to resolve settlement issues that can arise for IFM storage resources providing distribution services and participating in the wholesale market. A system is needed to measure the services in a particular settlement interval to differentiate whether the storage device was participating in wholesale markets or providing a distribution service.

If an IFM storage device is providing both wholesale and distribution level services, there is no need for separate wholesale and retail meters (although separate metering or estimation for station power loads is required). The procurement contract will specify how the interval meter data will be used for settling the distribution level service. Losses at the feeder level can be updated, whether or not there is storage. DSOs are constantly updating their distribution systems and can update distribution loss factors to reflect such changes.

As the settlement periods become closer together settlements become more challenging because it is necessary to distinguish (i) which electrons were used for distribution purposes and which were used for wholesale purposes, and (ii) which portion of retail station power use is allocable to the retail service and which portion is allocable to the wholesale service. As SCE pointed out, imbalance settlements with the CAISO raise a further level of complexity as it will be necessary to decide which entity(ies) are responsible for imbalance charges and which are entitled to imbalance payments. Resolution of these settlement challenges was not attempted at the March 13, 2018 working group meeting as the Energy Division staff lead requested that settlement issues be addressed at a later time.

2.2.2 Capacity Differentiated MUA

Questions were raised regarding the logic of physically partitioning and metering IFM storage capacity for the purpose of providing different services. It seems inefficient to prohibit an IFM storage device from providing a service from another available partitioned capacity from the same device simply because the other contractually-designated partition may not be available.

CAISO's biggest concern for transmission-level storage participating in a MUA is reliability. The CAISO is concerned that what an IFM storage device is doing when not supplying transmission reliability services may compromise its state of charge and jeopardize the ability to provide the transmission reliability service when needed.[38]

LS Power, with CESA's concurrence, stated that the CAISO's state of charge (SOC) variable can be used to maintain a buffer for provision of another service. Additional capacity reserved for another service wouldn't be made available via the SOC communicated to the CAISO; it would only be available on the storage device's control system. The CAISO would use the SOC to dispatch the unit. There would be no need to tag specific portions of a storage device to a function. From the CAISO's perspective, it only needs to know that the resource is available for whatever wholesale market services the IFM storage device is awarded.

In this case the physical portion of the resource available to the CAISO is what would be modeled and presented to the CAISO. If the SOC is provided to the CAISO for optimization, it should somehow reflect the available capacity for only the amount modeled presented to the CAISO. It could be that in these cases, the SOC would be managed by the resource owner. Any offers/bids submitted into the CAISO markets would need to be consistent with what was modeled and presented to the CAISO. The question remains in how to differentiate through meter data, only the portion that is modeled and presented to the CAISO.

When the CAISO filed its proposed DERP-A tariff with the FERC, parties pushed back that all resources in a DERP-A must have to interconnect under a wholesale market tariff. FERC said no, the resource just has to be interconnected.

PG&E noted that under a Participating Load Agreement (PLA), each meter may be linked with a single Scheduling Coordinator.[39] Some parties indicated that the one meter/one Scheduling Coordinator rule may be a barrier to capacity differentiated MUAs. There is likely to be confusion as a result of measuring different capacity services especially when those services happen close together or in some instances overlap. For example, when actual charge/discharge quantities differ from what was

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[38] CAISO has commenced a new initiative focusing on the use of storage as a transmission asset. *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/StorageAsATransmissionAsset.aspx An issue paper is available at http://www.caiso.com/Documents/StrawProposal-StorageasaTransmissionAsset.pdf. The CAISO acknowledged that there are implications for the CAISO's Transmission Planning Process but is recommending that those issues be dealt with in the TPP.

[39] The PLA is the agreement entered into between the CAISO and a Participating Load or a Non-Generator Resource.

dispatched/scheduled, there needs to be consideration for how those imbalances will be trued up. It is therefore important to establish a set of rules to consistently measure and treat imbalances (scheduled versus actual) to have a consistent way of measuring and to avoid optimizing/gaming after the fact. The Participating Generator Agreement (PGA) and Participating Load Agreement (PLA) forms may be merged into one and the PLA form eliminated.[40]

Parties asked whether processes have been developed for "scheduling" distribution-level resources that provide both distribution-level services and wholesale services. SDG&E, with PG&E's concurrence, stated that operational control is needed for distribution reliability services. If an IFM storage resource is needed for a distribution level reliability service, then it will need to use the CAISO's OMS to notify the CAISO that the resource is out of the wholesale market; the DSO would then be in control. The CAISO OMS system would reflect only the physical outages related to the portion of the resource that was modeled and presented to the CAISO. As noted above, there are questions as to whether the use of the OMS system is sufficient to remove an IFM storage resource from the wholesale market.

2.2.3 Simultaneous MUA

There appears to be agreement that simultaneous MUA are quite limited. Simultaneous provision of distribution and transmission reliability services from the same IFM capacity at the same time is prohibited. LS Power noted that simultaneous MUA with grid services can work safely if and only if the IFM storage device is getting a signal from the DSO that the DSO does not currently need energy to alleviate a thermal constraint.

However, LS Power believes voltage support (or any reactive power use case) can be safely combined with just about anything, anytime. However, SDG&E cautions that the ability to simultaneously provide energy and reactive power is subject to the thermal limit of the inverter. If the inverter is charging or discharging at full thermal capability, the production or absorption of reactive power will overload the inverter. The CAISO currently does not have a reactive power market. For IFM storage devices interconnecting to the distribution system under wholesale tariffs, the power factor range must be maintained within the same range as the DSO. This means that the storage device can only offer services at its rated real power level if it can simultaneously produce or absorb reactive power within the same range as the DSO.

2.2.4 Distribution Deferral Services

Considering the question of how to treat unaccounted energy for distribution deferral services, CESA observes that there may be a desire to explicitly measure the energy or VARs in and out of a distribution-connected IFM storage resource. CESA believes such measurement makes sense for *tracking* the performance of the IFM storage resource and for ensuring reliable distribution system operations; but, CESA thinks the need to *track* performance should be differentiated from energy *settlement*.

[40] The PGA is currently the agreement between the CAISO and a Participating Generator. A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the CAISO Controlled Grid form a Generating Unit with a rated capacity of 1 MW or greater.

For settlement, some options are: 1) settle as wholesale energy (via CAISO settlement), 2) settle as retail at some assigned retail rate, or 3) don't settle directly and instead treat as "system losses" which are indirectly settled as Unaccounted for Energy (UFE).

SCE disagrees with this assessment. To the extent that the source of energy is known (i.e., consumption, or generation / discharge), it should be accounted for at the source. The CAISO is currently working on a stakeholder process, "Excess Behind the Meter Production," in which the CAISO is attempting to address the production of energy from BTM resources on the distribution system in excess of the load from the specific meter location. This initiative recognizes that such production has a significant impact on the quantity of energy through the wholesale market to serve load. Much like that effort, any energy produced in response to a distribution need will similarly have a significant impact if not accounted for appropriately within the CAISO settlement process. As a general matter, SCE prefers to account for known energy directly and explicitly, as doing so is consistent with causation principles. Allowing such energy production to be accounted for as UFE violates this principle.

CESA believes that treatment as system losses is the most appropriate approach since that is how all distribution system losses are settled. CESA added in later comments that storage as a distribution asset should be treated as any other distribution asset when providing distribution services, especially if the charging aspect of the storage supports the provision of the distribution service just as the discharge aspect of the storage does. This similar treatment should apply for outage procedures as well as UFE settlement. At a minimum, for simplicity and practical reasons, storage charging should be treated at wholesale LMP when providing both wholesale and distribution services, as it is simpler to settle everything at wholesale when IFM storage is providing both wholesale and distribution services. In CESA's view, IFM storage providing wholesale and distribution service is becoming an increasingly viable use case, and it is impossible to determine which portions of charging energy was dedicated toward the wholesale service versus the distribution service. Most of all, CESA believes settling at retail for energy storage charging for a distribution-connected IFM storage resource. In CESA's view, even though charging energy for storage as a distribution asset is not intended for 'resale' in the market, the usage of the IFM storage resource is clearly different from end-use customer use, or the normal categories of use that are deemed retail.

In response to CESA's comments, SDG&E stated that for distribution deferral service, it is inclined to let the CPUC-approved contract between the UDC and IFM storage provider govern the energy settlements, and where such contract does not address such settlements, let existing tariff rules govern (e.g., if an IFM storage provider interconnects under the Wholesale Distribution Access Tariff (WDAT), then CAISO tariff rules would presumably govern energy settlements). However, SDG&E acknowledged that there could, in theory, be an IFM energy storage resource that intends to provide distribution deferral services and not participate in the CAISO markets. Currently, SDG&E has no retail tariff that would allow this IFM storage resource to interconnect to SDG&E's distribution system.

Summarizing, SDG&E contends that distribution deferral is a distribution reliability service and not a wholesale market service. Therefore, unless the charging and discharging energy is separately arranged and settled through the CAISO market mechanisms, SDG&E doesn't believe the energy should be uniquely wholesale. PG&E sees merit in SDG&E's perspective and agrees that the question of rate treatment for IFM storage providing distribution deferral services should be examined further.

SDG&E also disagrees with CESA's suggestion that energy associated with an IFM storage resource providing distribution services should be treated as "system losses." An IFM storage resource is not a passive device supporting the transport of energy (like a line, transformer or capacitor bank). Rather the storage device is actively charging/discharging energy and utilizing the transmission and distribution systems to do so. Moreover, if the charging and discharging energy were treated as "losses" then there is little incentive to operate the IFM storage device efficiently, which could be a negative impact on energy markets and result in an overall loss of consumer welfare.

2.3 Proposed Solution(s) for Station Power

During the March 13, 2018 working group meeting, certain storage developers observed that utility metering personnel generally insist on the highest quality of metering, even for station power consumption.[41] Storage developers argue that such metering may be cost prohibitive for certain IFM energy storage resources, especially if it is physically challenging (or practically impossible) to insert metering to capture all station power use.[42] LS Power recommended that UDCs allow the use of a "baseline" methodology to measure station power use. Also, during the working group meeting there was an analogous discussion around grid losses. Today, storage devices (such as capacitors) that provide transmission level services do not have specific metering requirements.

There was a suggestion that to ensure fairness between (i) utility grid assets (e.g., a transformer where the costs of transformer losses are recovered from loads and generators through the loss component of Locational Marginal Prices (LMPs)), and (ii) IFM storage resources (which may be providing a transmission service such as voltage control)), station power use need not be measured. Others contend that the general national practice is to presume that station power is simply part of a sale for resale and is thus settled completely at wholesale and without any sub-metering or estimation. If station power use is not measured, the costs of this energy would similarly be recovered from loads and generators through the loss component of wholesale LMPs. For these reasons, CESA believes it is reasonable to consider estimation methodologies for measuring and settling station power loads.

PG&E disagrees with the statement that station power use for utility grid assets is not measured. In fact, station power use at PG&E's substation is metered and accounted for. PG&E billing department issues a monthly billing statement for station power for substations. PG&E does agree that losses connected with the transformation of voltage are recovered from loads and generators through the loss component of the LMP.

Performance measurements for some services may already have established standards or such standards may be under development. For auxiliary load measurement, however, an array of performance measurements has been discussed. CPUC ED stated that D.17-04-039 and resultant IOU tariffs allow for estimation, set asides, etc. in selecting or authorizing which of these methods to use, there are different pros and cons. At one extreme, every individual auxiliary load can be metered and

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41 Station power refers to load used at a resource site exclusively for the production of power. Station power generally includes retail or "consumption" loads such as the control facilities and onsite staff facilities. Station power excludes wholesale loads such as charging energy, pumping load, synchronous condenser load, or blackstart load. It also excludes auxiliary loads not used for the production of power.

42 The CPUC leaves it to the generator owners and host utility to agree on appropriate retail metering arrangements.

settled via station power netting provisions. At the other extreme, no auxiliary load metering can occur, and auxiliary loads can be approximated through proxies, estimation, sampling, etc.

For multi-use energy storage, the different services may require different levels of station power measurement. For distribution service, for instance, the concept of station power netting is likely inapplicable as the full costs of the resource are (traditionally) recovered through cost-of-service calculations. Wholesale market services, by contrast, do support station power netting and thus promote consideration of auxiliary load netting. When combining different services, the need to measure auxiliary loads may not always be meaningful.

SDG&E recommends the use of revenue-grade meters, where feasible, to record station power consumption.

LS Power and the CAISO suggested that there is no need to "meter down to the kW." Estimation for station power should be permitted. LS Power asserted that if an IFM storage device is connected with only one line, all the necessary settlements can be done by measuring the flows over that one line. LS Power stated that the only case where you need more than one meter, is the case where a separate set of wires is serving station load.

The IOUs disagree. If an IFM storage device is providing both distribution and wholesale services, it will be necessary to distinguish (i) charging and discharging energy, from (ii) station power use in order to properly attribute station power use to the distribution and wholesale services.

The CAISO is currently in the process of implementing station power tariff provisions that allow for any netting or inclusion of station power within wholesale demand that is allowed by Local Regulatory Authorities (LRAs) such as the CPUC. These tariff provisions permit station power use to be allocated and settled consistently between wholesale and distribution services. The CPUC's station power tariff provides for netting on a 15-minute interval basis.

The CPUC's station power tariff provides guidance on what types of load do not constitute station power consumption (e.g., "…all load for…thermal regulation") and specifies when station power consumption is to be billed at retail and when station power consumption is to be settled as wholesale energy. In general, a "netting" algorithm is used to establish the settlement intervals in which all station power consumption will be billed at retail and conversely the settlement intervals in which there will be no retail settlement for station power consumption.

The CPUC's station power tariff, however, does not settle on all issues related to station power netting. Rules and a consistent accounting structure for the settlement of distribution level services are needed. LS Power confirmed that these systems do not exist now. (Given the capabilities of SDG&E's existing billing system, distribution level services provided by an IFM storage resource would currently be settled via manual processes.) PG&E indicates that they are still working on system changes to incorporate "E-STORE," PG&E's CPUC-approved tariff for IFM storage resources.

For MUAs, once systems for auxiliary load measurement and performance measurement are cemented, a secondary challenge is to differentiate and assign auxiliary loads to the applicable services.
By "auxiliary loads," we refer to loads at the resource site that are not station power but affect the net output of the resource. In this manner, cost-of-service services can bear the appropriate costs, and market services that allow permitted auxiliary load netting can also be calculated.

The apportionment of auxiliary loads may be immaterial or inapplicable in some cases, but CPUC guidance on methodologies for MUAs could be essential to avoid lengthy delays or disputes between parties, e.g., between an energy storage developer seeking to implement the approved auxiliary load netting provisions and the interconnecting utility. As discussed in the MUA working group, even simple 'one-service' energy storage projects have experienced extended discussions with a utility merely to proceed on the already approved aux-load netting rule. It may be that utilities need to evaluate if they should comply with aux-load netting policies via 'ad hoc' approaches or via updates to their internal retail billing systems. In any auxiliary load netting solution, naturally, parties agree that wholesale-retail integrity should be maintained.

With respect to the IFM storage resources providing multiple services, CESA believes the following conclusions are appropriate for apportioning Station Power load:

1. Simultaneous: Apportionment issue does apply. Use a simple split (number of services) proxy to divide the allowable aux load between services.
2. Capacity-differentiated: Apportionment issue does apply. Use capacity split percentage to split and apportion.
3. Time-differentiated: Likely does not apply.

If providing both distribution services and wholesale services from the same capacity at the same time ("Simultaneous"), it was suggested that there needs to be some mechanism to allow the IFM storage resource to get out of its wholesale market obligation. It was asked whether, in such a circumstance, the UDC would make the IFM storage resource "whole." After discussion, there was some agreement that distribution reliability services should have primacy for resources interconnected in the distribution domain.[43]

However, if the wholesale market obligation was for wholesale energy, and not a wholesale reliability service such as frequency control or spinning reserves, then the IFM storage resource could get out of its energy award, if necessary, by taking the CAISO's uninstructed deviation charge. An example is the case where the IFM storage resource has a day-ahead schedule that charges the device so that the device is prepared to provide energy, if instructed by the distribution utility, during prescribed hours later in the day. The day-ahead schedule for these later hours would be zero since the IFM storage device may not know, at the day-ahead stage, whether the energy will actually be called by the distribution utility. If the energy is called by the distribution utility, then the IFM storage device will discharge and thereby deviate from its original scheduled 0 MW. The difference between the scheduled versus actual quantity will be settled by the CAISO as an uninstructed deviation.

To summarize, if the provision of a non-reliability wholesale service would compromise the ability to provide a distribution reliability service, the latter should prevail and the CAISO would settle the non-reliability wholesale service (such as the provision or consumption of energy) as an imbalance.

[43] Please refer to chapter on Ensuring Resource Performance (Rules 6 – 10) on energy storage resources delivering two or more reliability services.

Multiple Use Applications for Energy Storage Working Group Chapter 3. Incrementality & Rule 11 (Utility Position)	
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1. Synopsis

This section of the MUA Working Group Report includes discussion and recommendations on Rule 11 of the MUA Rules adopted in the Commission's Decision (D.) 18-01-003, which states:

> "Rule 11. In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation."[44]

As further discussed in this chapter, it is the Investor Owned Utilities' (IOUs or the Utilities) position that revisions to Rule 11 are not needed at this time for providing guidance on treatment of energy storage services as incremental to avoid double counting and double compensation. However, because D.18-01-003 did not provide certain definitions, such as a definition of "incremental," a few definitions and examples of Rule 11 application could be adopted to further clarify this Rule if necessary. As such, this section of the Working Group report discusses how "Incrementality" has been defined and applied in other proceedings (e.g., the Integrated Distributed Resource (IDER) proceeding, Demand Response (DR) proceeding's dual participation rules), and how the incrementality definition may be applied to storage devices that provide MUAs.

This document also discusses the following issues:

- **Issue 1:** Are there different categories of incrementality and is there a need for a new rule to address procurement incrementality separately from compensation incrementality as suggested by industry stakeholders?
- **Issue 2:** Is there a difference between typical use and expected use?
- **Issue 3:** Should expected use be determined based only on contractual commitments?
- **Issue 4:** How do incrementality rules apply to specific use cases identified by industry stakeholders?

In addressing the aforementioned issues, this document offers the following recommendations:

- **Recommendations to Address Issue 1:**
  - The IOUs recommend that Rule 11 remain unchanged.
  - The Utilities recommend that the Commission reaffirm IDER principles to determine incrementality of offered products and services.
  - The Utilities caution the Commission that it should not require, at this time, specific methods or calculations to prescriptively determine incrementality in any given situation. The utilities believe that in most circumstances, incrementality would depend on the specific use case and specific product/service being offered. Once the Commission, the utilities and the stakeholders have sufficient experience with multiple-

[44] See D.18-01-003, Appendix A, p. 2.

use resources and their underlying commercial arrangements, uniformity and consistency in such calculations could be explored if needed.

- **Recommendations to address Issue 2:**
  - The Utilities recommend that the Commission clarify that "expected use" forms the basis of determining incrementality, and that the resource's typical use is one of the factors in determining its expected use. Typical use is generally backward looking whereas expected use is forward-looking.
- **Recommendations to address Issue 3:**
  - The Utilities recommend that the Commission clarify that expected use of a BTM resource, as used for distribution operations and in distribution planning, should not be based solely on prospective contractual commitments, effectively measuring against a baseline of zero. Instead, expected use should be based on many factors, including participation in and intent of utility tariffs and programs, past behavior and data collected through SCADA systems, or other mechanisms, in addition to contractual commitments.
  - While the MUA workshops may identify issues with the CAISO MGO process, the Utilities believe that modifications to the baseline methodology should be considered in the CAISO Energy Storage and Distributed Energy Resource (ESDER) proceeding to effectuate any necessary changes.
- **Recommendations to address Issue 4:**
  - The Utilities do not, at this time, have specific recommendations for the Commission as to how incrementality rules should apply to specific use cases. However, as discussed below, the Utilities do have perspectives on the incrementality of the use cases proffered by the industry stakeholders. The Utilities believe any specific recommendations for the Commission require more experience with BTM storage in multi-use applications.

2. Background

D. 18-01-003 adopted the following Rule: "Rule 11. In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct.
Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation." A simple interpretation of this Rule is that in order for any storage device to be eligible to offer a service to a buyer, this service must be incremental and measurable so that the "same service" is measured accurately, and is only counted and compensated once.

Even though D. 18-01-003 did not include an explicit definition of "incremental," the concept of incrementality has been addressed previously by the Commission and by the CAISO, including relevant definitions. The IOUs describe below how incrementality has been addressed elsewhere.

The IOUs believe that an example of prohibited "same service" would be the sale of the same energy to two different buyers, e.g., energy sold to a utility via a contract or a tariff, and the same energy also bid into a CAISO market. Another example of same service would be offering the same capacity that is already participating in a utility demand response program into a utility's separate capacity procurement mechanism such as Demand Response Auction Mechanism (DRAM).

2.1 How the Commission has dealt with Incrementality in the IDER Proceeding

The Commission formed a Competitive Solicitation Framework Working Group in the IDER proceeding. This working group identified incrementality as an issue and made recommendations to address this issue in the IDER proceeding. The Commission extensively discussed this topic in its decision D.16-12-036 and provided further guidance on incrementality in its Resolution E-4889 approving the IOUs' advice letters to launch the IDER Pilot RFOs.

- **<u>IDER Principles</u>**

The Commission's decision in the IDER proceeding, D.16-12-036,[45] provided the following guidance on incrementality:

- Ensure that ratepayers are not paying twice for the same service;
- Ensure the reliability of a service, i.e., ensure it is not counting on a service to be there when the service might be deployed at another time or place;
- Be technology-neutral;
- Be fair and consistent;
- Recognize that a distributed energy resource is eligible to provide multiple incremental services and be compensated for each service; and
- Be flexible and transparent to bidders

The IOUs believe that D.16-12-036's principles are consistent with guidance provided in D.18-01-003,[46] which states that "Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation. As a general rule, a utility, UDC, or the ISO should not be required to **procure or pay for** a service that the entity has already planned and paid for." (Emphasis added)

- **<u>IDER Definition of Incrementality</u>**

The Commission defined incrementality in its Resolution E-4889 in the IDER proceeding when it said, "Services offered by existing DERs that are **above and beyond what is expected** under other programs should be considered incremental." [47] (Emphasis added). The IOUs have interpreted this definition as meaning that DER services (including energy storage services) are incremental only to the extent that they are above and beyond the otherwise expected performance under normal circumstances.

The Commission further affirmed in its Resolution E-4889 that the "Bidders must be convincing in presenting a plan that will result in incremental savings relative to existing programs, and must include a robust methodology to verify claimable (incremental) savings and avoid any possible double-counting of savings." [48] The IOUs have interpreted this stipulation as requiring the bidders to provide credible evidence to the utility during the procurement process that the services they are offering are above and beyond what the IOUs would otherwise have expected.

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45 D.16-12-036, pages 18-19
46 D.18-01-003, Page 49
47 Resolution E-4889, page 27
48 *Id.*

- **IDER Incrementality Methods and IOU Implementation**

The IOUs have implemented this guidance in their respective RFOs/RFPs by seeking Commission endorsement of the IOUs' incrementality methods. SCE filed its Advice Letter 3620-E on June 15, 2017 proposing its incrementality methodology.[49] SCE proposed a methodology that combined Methods Four and Five from the Competitive Solicitation Framework Working Group[50] Final Report. Method Four is a tranche analysis that envisions three categories of DERs: (1) those not already sourced through another channel, (2) those partially sourced through another channel, and (3) those wholly sourced through another channel.[51] Method Five, similar to Method Four, suggests that when the attributes of a DER have not been expected through other mechanisms, they should be considered incremental, and if they have been obtained partially through another mechanism, a portion may be considered incremental if the bidder can demonstrate increased market participation due to the combined incentives.[52]

Consistent with this hybrid approach, SCE filed an incrementality matrix that detailed how resources would be treated for purposes of the solicitation. SCE's approach was approved by the Commission and SCE utilized it to determine incrementality during the RFO.[53] SCE recommends that the matrix be used as an initial basis for incrementality evaluation going forward.[54]

SDG&E does not agree with all aspects of the incrementality matrix presented filed by SCE and stresses that incrementality needs to be evaluated on a case-by-case basis. The future need, capabilities of technology, and potential use cases are still evolving, including in the IDER/DRP proceedings, and therefore SDG&E recommends against adopting premature prescriptive methodology. Rather, SDG&E advocates for reaffirming the IDER principles as the guidance to the IOUs. This ensures a consistent incrementality approach, while allowing for changes in process and technology.

In addition, SDG&E is concerned about providing additional value for benefits that are already delivered, compensated, and accounted for through existing programs like NEM and SGIP. For example, at the present, SDG&E believes that both existing and future resources that receive the SGIP or NEM incentives under the current SGIP and NEM tariffs, should not be considered incremental. The resources procured under these tariffs and programs are being subsidized with generous incentives at the expense of all ratepayers. These tariffs and programs are aimed at providing grid benefits (i.e., providing capacity, energy and reducing GHGs) even though many of these benefits are not being realized. Before considering whether any of these resources are capable of providing incremental services, SDG&E believes it is necessary that these tariffs and programs be modified such that their costs are brought in line with the benefits provided. Once NEM and SGIP are restructured so that the benefits match the payments, it may be appropriate to consider whether a participating resource can offer an incremental benefit that deserves incremental compensation. Without clear alignment between benefits provided and compensation in these existing programs, it is impossible to determine whether incremental value exists.

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49 SCE Advice Letter 3620-E, June 15, 2017 at p. 10-12.

50 Administrative Law Judge's Ruling Establishing a Working Group to Develop the Competitive Solicitation Framework, R.14-10-003, March 24, 2016, at 3.

51 D.16-12-036 at p. 10.

52 *Id.*

53 Resolution E-4889, page 29

54 This matrix was presented at the April 20, 2018 MUA working group meeting

As a general matter, SDG&E believes the existing SGIP and NEM programs were modified to create strong incentives for storage resources to discharge in accordance with existing Time of Use (TOU) rate schedules. Because of the clear intent and robust compensation for these programs, and because distribution system capacity needs are generally correlated with these TOU periods, SDG&E finds it inappropriate to consider these storage resources as providing incremental services or value to all ratepayers. Providing separate payments for distribution deferral to storage resources that already receive incentives through SGIP and NEM to discharge in accordance with TOU rate schedules, for example, would constitute double-compensation, which is prohibited by Rule 11.

2.2 How the Commission has dealt with and instituted procurement and compensation methodologies for DR to address incrementality, counting, and double-compensation in the DR proceeding

The Commission has previously addressed similar concerns regarding a customer participating in two DR programs, whereby such dual participation could lead to double payment to the customer, and without the proper guidelines for accounting, it may also lead to overstated load drop estimates.

As background, there are a variety of methodologies instituted and approved by the Commission to evaluate what the resource can provide as part of a DR tariff or contract (i.e., DR Auction Mechanism). These methods and process are contingent based on whether the DR program is administered and operated by a utility or third-party DR provider. For utility administered and operated DR program, Load Impact protocols are used to determine the RA quantity provided by a customer or third-party aggregator. Load Impact utilizes the ex-post performance from each of the participating customers or aggregated customers which is then used to develop an ex-ante forecast for the years' ahead.

While Load Impact is the primary method used for utility administered and operated programs, third-party operated via DRAM utilizes the third-party scheduled contract amount. This scheduled contract amount is given by the third-party at the time of the solicitation and the method used may be relying on a settlement baseline (i.e., 10-10 baseline) or proprietary methodology created by the third-party. If a proprietary approach is used, there are reconciliation challenges and questions as to whether the contracted amount is in fact achievable when operating.

Unlike the aforementioned methods used for quantifying DR procurement, the CAISO's DR participation model (PDR and RDRR) and IOUs' DR program utilizes baselines to calculate the performance of BTM resources. Baselines, such as 10-10 with morning adjustment and firm service level, to name a few, are approved methodologies by the CPUC, to settle retail DR compensation, or by FERC to settle DR resources' wholesale energy performance.

The Commission, in its decision D.09-08-027, concluded that DR dual participation "is reasonable and consistent with the Commission's policy of encouraging cost-effective demand response activities to allow customers to participate concurrently in two demand response activities and programs, as long as duplicative payments for a single instance of load drop can be avoided." The Commission recognized that "in the case of simultaneous or overlapping events called in two programs, a single customer enrolled in two programs will receive payment only under the capacity program, not for the simultaneous event for the energy program." These guidelines have balanced the recognition that customer should be able to participate in more than one DR program so long as that safeguards are established to avoid over compensating the customer and that accurate counting procedures are implemented.

2.3 How the CAISO has dealt with incrementality

In 2016, the CAISO adopted and FERC subsequently approved the MGO Baseline methodology for measuring performance of sub-metered resources, separately from the whole customer premise, that are participating in wholesale markets through the Proxy Demand Resource (PDR) and Reliability Demand Response Resources (RDRR) mechanisms.[55] CAISO's MGO baseline is fundamentally a method to evaluate the storage resource's wholesale energy market performance incremental to its previous performance for the customer premise.[56] The MGO Baseline determines incrementality by measuring resource performance on an "event" day in comparison to average resource performance during 10 previous "non-event" days. Here incrementality was defined as performance of a service in comparison to the "typical use" of the resource.

Traditionally, a baseline method utilizes the customer's metered load only (i.e., the customer overall premise revenue meter, which captures the battery meter read) and is designed to measure an actual drop in load. As a simple example, if in the prior ten similar hours, the CAISO determined the load to be 5, 8, 7, 4, 6, 5, 6, 7, 8, 8 MW then the baseline for the demand response based upon load would be the average of these load measurements, i.e., 6.4 MW. Then, for the hour in which the CAISO calls upon the resource to provide DR, the resource would be expected to consume less than the 6.4 average of the prior ten similar hours. In this case, "incrementality" is the amount that the load is reduced below the prior average of 6.4 MW.

The CAISO adopted three different MGO baseline options. The first option (MGO-B1) calculates the performance using a baseline of the net load data (i.e. considering both the gross load and generator output) of the resource at the premise level. The second option (MGO-B2) calculates the performance using only the generator output as measured by the battery sub-meter, i.e., the estimated typical energy output of the generator is compared against the output of the generator on the event day to calculate performance. The third option (MGO-B3) calculates the performance by using load and supply (i.e. a combination of the first two options above).

If the demand response participant is utilizing a battery to enable its load curtailment to the grid, the Demand Response Provider can elect the MGO methodology. In this case, rather than using the load measured at the customer meter, the baseline utilizes the sub-meter of energy output from the battery itself.[57] This method utilizes a baseline method, but for the battery output and not for the customer

[55] CAISO has suggested that in its Distributed Energy Resource Provider (DERP) framework, the preference is to directly meter the DERs to determine their performance based on ISO dispatch or control, and that incrementality would be determined based on capacity/services offered to the CAISO and meter reads during the participating intervals. However, the IOUs believe that for any BTM resources, this approach does not measure changes at the utility meter and therefore should not be used in determining incremental impact on the grid from a distribution services standpoint.

[56] This does not take into account any changes in the customer's load, and therefore, does not measure any changes at the utility's revenue meter or the impact on the grid.

[57] Such baseline battery output may occur to provide other services such as peak demand shaving for the customer.

load. In this methodology (MGO-B2), the increases in load due to things like temperature can be addressed by evaluating the output of the battery assuming that increased battery output is a reduction in the load that would have been served by the grid otherwise. There are two notable exceptions when determining the battery output baseline that deserve discussion. First, the CAISO recognized that a behind-the-meter battery is interconnecting via a non-wholesale interconnection (Rule 21). As a result, the battery is not expected to export to the grid. In establishing the baseline for the battery output, the CAISO does not consider hours in which the resource exported to the grid as a similar prior hour. In addition, the CAISO does not compare to hours in which the demand response was dispatched at a price below the net benefits threshold test. This exception to calculating the baseline for the battery output is in recognition of the discharging by the battery to meet a dispatch that provided the appropriate value to the grid.

A simple example of this case is to suppose that the battery output on the ten similar prior hours was 2,1,1,3,2,1,1,3,3,2. This would produce a baseline of the battery output at 1.9 and “incrementality” would be any battery meter output above the 1.9 regardless of the host facility load. Similarly, under the same methodology, in periods where the battery output was negative (i.e. the battery was charging during the measured baseline period) than those numbers would be grossed up to zero. This example would be the case when the battery output of 2,1,1,-3,2,1,1,3,-3,-2 would be modified under the MGO Baseline methodology to be 2,1,1,0,2,1,1,3,0,0**.** This calculation was raised at the working group and flagged as something to be further discussed in the CAISO ESDER proceeding.

The baselines are the product of the CAISO ESDER proceeding and the CAISO governs how resources are integrated into the wholesale market. While this working group may identify issues with the baseline methodology, any recommendations of changes should be teed up and discussed in the ESDER forum.

2.4 Working Group Discussions

The Working Group has extensively discussed this topic over a few meetings. Summary of these discussions is provided below. In addition, this topic was also referred for further discussion among Stem and SCE, with a few other parties also joining this discussion. Stem and SCE provided an overview of their positions during a working group meeting on June 7, 2018.

- **<u>Summary of Incrementality Discussion on April 20, 2018</u>**

The first meeting on incrementality focused on the IDER competitive solicitation framework, which was adopted in December 2016, as part of the IDER proceeding. The CPUC and SCE jointly presented on this topic and shared background on the IDER proceeding, as discussed earlier in this chapter.
The Competitive Solicitation Framework Working Group in the IDER proceeding had proposed five different methods for measuring incrementality. Of the five methods discussed, the IOUs generally agreed that a hybrid approach of two different methodologies would be most appropriate for assessing and compensating incremental resources – “Method 4” divides offers in the solicitation into three different tranches; and “Method 5” additionally considers attributes of DERs that have not been sourced through other mechanisms. In the IDER proceeding, Commission Resolution E-4889 approved (with modifications) the incrementality framework and criteria, as generally described here.

Method 4 was originally proposed by SCE in the Local Capacity Resource (LCR) RFO process in 2013. The three tranches in Method 4 include: (1) wholly incremental, (2) partially incremental and, (3) not incremental. Partial incrementality refers to resources that may already be receiving compensation through existing programs or resources, but which also offer services that are above and beyond that which they are being currently compensated. As noted by SCE, technology incentive programs, such as SGIP and NEM, often fall in this category. Furthermore, the utilities contend that programs including NEM and SGIP, already provide compensation significantly in excess of the value of services provided.[58]

In response to the SCE's characterization of "partial incrementality," Stem noted that SGIP, as a technology incentive, should not be included in discussions of incrementality related to services. Rather, the SGIP performance incentive only requires cycling the battery to ensure that the technology functions adequately. Stem held the position that there was no way an SGIP storage resource should be viewed as already providing any level of grid benefits based on the current cycling requirements, and that the entirety of the SGIP storage should be considered incremental from the perspective of providing grid services. The IOUs disagreed with Stem's characterization of SGIP resources, for several reasons described later in this document while discussing the SGIP use case. It should also be noted that along with the existing cycling requirements, D.15-11-027 had updated a round-trip efficiency (RTE) metric to determine if SGIP energy storage systems' operations resulted in reduced GHG emissions. Under R.12-11-005, there is a formation of a working group to develop a proposal for a greenhouse gas signal and enforcement mechanism for energy storage systems participating in the Self-Generation Incentive Program to ensure these projects reduce greenhouse gas emissions (i.e., by helping reduce peak loads).

The Working Group noted that nothing in the MUA framework intends to modify the means by which services are compensated today. Rule 11 merely requires that services be measurable and distinct (incremental) in order to be compensated. Given Rule 6, the only instances by which incrementality should matter are those in which services are perfectly simultaneous or in cases where time differentiation of services would compromise one another. Stem discussed the principle of compensating resources for retail activities *only if* such activity is not already included in a Load Serving Entities (LSE) forecast. Stem also presented underlying principles to guide compensation and incrementality: (1) Establish the baseline value; (2) focus on dollars rather than on energy production; (3) must have a market to determine whether a service is incremental and a static point to measure against; (4) customer capacity and system capacity are different things; (5) for incrementality, both energy and capacity elements are important; (6) domains are important for determining incrementality. There was disagreement, with some IOUs noting that the focus should be on demonstration of eligibility to offer incremental services in the procurement process, which would then lead to commercial transactions between a buyer and a seller for the eligible service, with the underlying agreement's terms and conditions determining compensation for the service rendered.

- **<u>Summary of Incrementality Discussion on May 3, 2018</u>**

[58] The IOUs believe that if the Commission allows multiple pathways for the same storage system to earn revenue, it should also reform various technology incentive programs to bring compensation more in line with the value provided to the grid. Furthermore, better performance requirements should be adopted in these programs so that the non-participating customers obtain corresponding benefits for the generous payment they are making.

During the second working group session on incrementality, Stem indicated its position of three different types of incrementality: (1) mandate incrementality – referring to how storage is counted against policy mandates; (2) procurement incrementality—described as the determination of whether a resource is providing the same service to another entity, or whether the resource is already partially or wholly dedicated to another service; and (3) compensation incrementality – described as the determination of whether the resource is being overcompensated for the incremental value provided. According to Stem, the compensation incrementality is the focus of the MUA working group and includes topics such as the MGO baseline.

The MGO baseline was created to avoid double compensation between retail and wholesale services, by first determining the typical use of a battery using a 10-in-10 baseline. There was robust discussion regarding this baseline's rules and their application, and whether this baseline represents "expected use." There was also a discussion regarding behind the meter resources' role in various forecasts. The CEC's Demand Forecast includes the activity of behind-the-meter DERs (such as electric vehicle use, rooftop solar photovoltaic, energy storage devices) and TOU rate impacts, and thus, in the aggregate, the activity of the storage device is taken into account, as commented by SDG&E. The CAISO responded that it does conduct a forecast, and then adjusts the demand for each day up to an event day.

The Working Group discussion then focused on specific use cases for storage that is paired with a NEM-eligible system, and how this type of resource should be assessed and compensated for incremental services for participating in the DRAM. When a DRAM event is called, the storage device is used to mitigate the customer's total onsite load. Energy that is sold back to the utility is still credited to the customer at the NEM rate. The NEM rate is a full retail rate credit which includes generation, distribution, and transmission components. It was noted that NEM systems with storage can participate as PDR and in the DRAM (e.g., Sunrun has DRAM contract). The aggregated capacity benefit is load dependent and any exports are not allowed to accrue a credit under the current PDR rules.

It became unclear from the Working Group discussion whether the storage NEM use case does or does not represent an incrementality issue. SDG&E stated that if the customer has a rate design incentive (e.g., Time Of Use (TOU) rates) to motivate storage behavior (e.g., use the storage to shave the customer's peak usage), such behavior is most likely to coincide with the hours of highest system need. Stem responded that there's a big difference between making capacity available via an RA contract vs. this capacity's expected response to a TOU rate. Demand Energy pointed out that, if we are executing against a rate design, a few more MWs may be available for other services. The IOUs' perspective is that at a minimum, customers' rational behavior in response to an appropriate TOU rate design would constitute the expected use benchmark, from which incrementality would be measured.

A few outstanding questions from this discussion, which are further addressed in this chapter, are: What is the residual amount of capacity, if any, that is left over beyond NEM expectations? How does one measure *just* the performance of that incremental capacity? Some of these questions may warrant referring to the RA proceeding.

3. Utility perspective on incrementality issues raised in MUA WG process

Several issues have been raised on the topic of incrementality during the MUA working group discussions. The following is an attempt to identify and address these issues.

<u>Issue 1 – Are There Different Categories For Incrementality? Is There A Need For A New Rule To Address Procurement Incrementality As Suggested By Industry Stakeholders?</u>

- **Issue Statement:**
  - Industry stakeholders have argued during the working group process that incrementality should be categorized in three buckets, namely, Mandate Incrementality, Procurement Incrementality and Compensation Incrementality.
    - Industry stakeholders argue that product incrementality is determined at two distinct stages, namely, during the solicitation/procurement process and also during the financial settlement after performance of services, i.e., the compensation process.
  - Industry stakeholders have argued that Rule 11 deals only with the compensation process, and that a separate Rule dealing with incrementality determination during the procurement process is needed.
    - In making this argument, the Industry Stakeholders appear to suggest that each domain (i.e., customer, distribution and transmission) should make an independent assessment of what was expected *in each domain* and the value added *only to that domain* (without taking into account any expected use and/or value already conferred to a different domain), and that the compensation incrementality should only be relative to the added value in that domain.
      - The CAISO has suggested that the implications on interconnection agreements, metering protocols and contractual obligations need to be discussed.

- **Utility Position:**
  - SCE and SDG&E disagree with the need for three different categories of incrementality. PG&E may not disagree with the categories, but believes that more examination of use cases is necessary to determine the appropriate categories. SCE and SDG&E also disagree with the industry stakeholders that a separate rule is necessary. PG&E believes that it is premature to have a separate rule until use cases are developed and further examined.
    - Mandate Incrementality, i.e., how much additional storage can be counted towards the Utilities' procurement mandates (e.g., related to AB 2514), is non-controversial and has not been raised as an issue.
    - Procurement incrementality, i.e., eligibility of a storage device to offer a product/service, should be determined relative to the otherwise "expected" outcome and will depend on the service required.
      - Expected outcome includes a forecast of new installations as well as expected performance of existing resources.
      - If procurement is done via competitive solicitations resulting in binding agreements, compensation is offered for actual performance of the contracted service pursuant to the terms of the agreement.

        - In all cases, the performance, i.e., the delivery of service must be measured accurately and must be incremental to an appropriate baseline that is agreed upon in the procurement transaction or required by the program rules.
    - The IOUs believe that domain-based limitations as articulated by the Industries proposed rules, i.e., customer, distribution, transmission domains, are unnecessary since, as explained by the industry stakeholders at the July 23, 2018 working group meeting, each domain is able to take into account services being provided in other domains while determining product and compensation incrementality. IOUs believe that incrementality should be determined based on expected use, regardless of which domain that use is meant for.
    - The IOUs disagree that value assessment and/or compensation should be limited to (i.e., contained within) each domain. Ultimately, each buyer is purchasing a product ("commodity") and the terms of the agreement should dictate which attributes of that product flow to the buyer.
    - The IOUs agree with the CAISO that if the Commission desires to create domain-based differentiation in incrementality or compensation rules, there are many important issues such as metering protocols and contractual obligations that need to be addressed.

- **Recommended Policy Changes**
    - The IOUs do not believe that Rule 11 needs to be revised or a new Rule 12 adopted at this time. Instead, the IOUs recommend that the Commission reaffirm the IDER principles to determine incrementality of offered products and services.
    - The IOUs caution the Commission against requiring specific methods or calculations to determine incrementality in any given situation. At this time, the IOUs believe that in most circumstances, incrementality would depend on the specific use case and specific product/service being offered.
    - Once the Commission, the utilities and the stakeholders have sufficient experience with multiple-use resources and their underlying commercial arrangements, uniformity and consistency in such calculations could be explored if needed.

Issue 2 – Is There A Difference Between Typical Use And Expected Use?

- **Issue Statement**
    - The WG discussions may have led the IOUs to believe that the Industry stakeholders were distinguishing between "typical use" and "expected use," with typical use potentially defined as "what the resource was going to do anyway" and expected use potentially defined as "what the market expected the resource to do."
    - Based on the comments received on the previous drafts of this section, it appears that the industry stakeholders are simply saying that "typical use" is backward-looking and "expected use" is forward-looking, and that incrementality determination needs to be based on expected use, not typical use, although typical use can be one of the factors in determining expected use.

- **Utility Position**
    - The IOUs agree that "typical use" is largely backward-looking and "expected use" is forward-looking, and that incrementality determination should be based on expected

use. The IOUs take into account typical use as one of the several inputs, along with other factors such as weather conditions, to assess an expected use (e.g. load profile).

- A market is a mechanism to balance supply and demand as efficiently as possible. If the resource's operating profile was already assumed to be a part of the supply or demand, then that profile is "expected" and is not incremental. An operating profile may be based on previous "typical" use, or it can also be based on expected rational behavior, or expected behavior in light of participation in utility programs that offer incentives towards a certain behavior profile.
- SDG&E believes the Commission should continue to focus on the term "expected" use to ensure decisions made do not jeopardize reliability. This underscores their recommendation against prescriptive rules developed around our assessment of incrementality.
- If the resource is offering a service that is different than its expected profile and intent, then the difference could be deemed incremental, but the burden to demonstrate that the resource indeed is offering a different service rests on the resource.
    - The industry section makes a request for IOUs to provide additional information so that the service providers can have clarity regarding how to price their bids. SCE finds this argument troublesome. The primary objective of competitive processes is to let market forces determine cost to our customers. SCE provides sufficient information so that offerors know precisely what is being solicited and why. SCE should not be required to share additional information that can potentially distort the market.
- Where a resource is already participating in a program, behavior to serve that program and the program's intent (including compensation) must also be included as "expected use" and must be included in the baseline against which incremental performance is measured.

- **Recommended Policy Changes**
    - The Utilities recommend that the Commission clarify that "expected use" will form the basis of determining incrementality, and that the resource's typical use can be one of the factors in determining its expected use, along with other factors such as program intent, weather conditions, etc. Furthermore, expected use or outcomes can include forecast of new installations as well as expected performance of existing resources.

Issue 3 – What should be used to determine incrementality for Contractual Commitments?

- **Issue Statement**
    - During the working group discussions, many assertions have been made from Industry Stakeholders that just because a BTM asset has acted a certain way in the past, there is no guarantee that it will act that same way the next time. CESA argues that there is some level of uncertainty for BTM resources responding to program requirements and incentives and tariff/rate incentives.

- Industry stakeholders appeared to argue that only contractual relationships provide certainty, and therefore, all dispatches that the asset provides pursuant to a contract should be deemed incremental to some degree.[59]

- **Utility Position**
  - Industry stakeholders' argument suggests that without an underlying contract or participating in a DR program that gives the utilities resource rights, the utility's "expected use" utilizing other utility technology programs (e.g., SGIP) and tariffs (e.g., NEM and/or TOU rates), will not realize the incremental resource potential during periods of grid needs.
  - The IOUs disagree with this position from a practical standpoint as well as from a policy standpoint. There are many Commission-approved pricing and incentive mechanisms, such as the IOUs' tariffs and technology-incentive programs, as well as the wholesale markets operated by the CAISO, that have been designed to motivate specific behavior by the customer. Not being able to rely on such expected performance undermines the foundational theory behind creating these types of offerings/programs, and also brings the fundamental premise/intent and policy justification to question for offering any incentives/compensation via such programs.
  - IOUs' planning tools do not separate such past behavior and identify future need based on an assumption that all past performance is to be ignored. Even where separate identification of past behavior is possible, an approach that ignores past behavior would cause IOUs to over-procure and cause customer costs to increase with no offsetting benefit.
  - Indeed, while future behavior may not exactly mirror past behavior, customer behaviors are generally predictable when adjusted for weather patterns, rate structures, and incentives from programs and tariffs. For a resource to be considered as providing incremental value, its operation would have to provide the additional attributes that the IOUs or the CAISO are looking for to fill the system need, while accounting for the resource's expected performance.
  - Baselines do and will play an important role in determining expected use, with the burden to offer evidence that can prove incrementality being the responsibility of the service provider.

- **Recommended Policy Changes**
  - The Utilities recommend that the Commission clarify that expected use of a BTM resource, as used for distribution operations and in distribution planning, should not be based just on contractual commitments. Such expected use can be based on many factors, including participation in and intent of utility tariffs and programs as well as past behavior and data collected through SCADA systems, or other mechanisms.
    - For example, an energy storage Demand Response resource can be incremental when, in conjunction with storage operation, the total net load of the site shows a drop compared to its typical load profile obtained from measuring the customer's retail meter. For a distribution service, the use of the CAISO's

[59] CESA clarified in its final round of comments that the industry stakeholders believe there can be varying levels of certainty to assumptions/forecasts of future performance. Specific contract provisions and specific operational requirements in programs provide the most certainty, whereas reactions to grid services calls, such as Demand Response calls, provide some certainty.

Metering Generator Output (MGO) baseline methodology, which only looks at the storage device's standalone performance, might not be appropriate unless in concert with the overall impact to the customer's premise load measured at the revenue meter.

- While the MUA workshops may identify issues with the CAISO MGO process, the Utilities believe that modifications to the baseline methodology should be considered in the CAISO Energy Storage and Distributed Energy Resource (ESDER) proceeding to effectuate any necessary changes.

Issue 4 – Examples of How Incrementality Rules Can Be Applied to Specific Use Cases

- **MGO baseline example, i.e., based on storage participating in CAISO PDR market while also providing BTM load management services to the host site**

  - **Example Use Case and Related Questions:**

    - For a single BTM storage installation providing customer service, e.g., TOU bill management, and participating in the wholesale energy market, e.g., the CAISO's PDR, how much of the measured energy discharge should be considered incremental for purposes of determining CAISO market compensation? If it is determined that there is incrementality, what baseline should the incrementality be measured against?
    - It is assumed here that the storage resource has elected to use the CAISO's currently-approved MGO Baseline methodology for performance evaluation, using the option to measure the direct battery meter only. A hypothetical scenario for this use case is that on the event day, the resource is dispatched to discharge 3 MW for 1 hour starting at 2 pm. On the 10 previous non-event, like days, the metered storage quantities at 2 pm were 1, 2, -2, -3, -3, -1, 0, 1, 1, 2 MWs where positive numbers are discharge and negative numbers are charging.
    - Assume further that net load at the customer's main utility meter for these hours was 5, 1, 5, 4, 6, 1, 0, 3, 2, -1, averaging 2.6 MW.

  - **Utility Position:**

    - The difference between metered output on the event day and the MGO baseline (0.6 MW) is the incremental amount of PDR service provided, and the compensation would accordingly be based upon this difference.
    - In this example, from a distribution services related incrementality standpoint, IOUs believe that it is not sufficient to simply determine the incremental amount of storage service provided by a behind the meter device based on the MGO baseline. The overall net load at the customer site (i.e., at the main utility retail meter) would also need to show a corresponding decrease for any storage service to be counted as incremental from a distribution service standpoint. SDG&E believes it is the responsibility of the CAISO to determine the incremental amount of PDR service provided.

- **SGIP Example**

- **<u>Example Use Case And Related Questions</u>:**

  - For an SGIP funded storage device offering to participate in a distribution deferral solicitation seeking distribution capacity, how much of the offer's capacity should be considered incremental? Are exports to the grid eligible as "incremental"? Against what baseline should any incrementality be measured?
  - A hypothetical scenario is that a utility issues a distribution deferral RFO for capacity resources that can perform for 2 hours with a call window of 3-9 pm on any weekday from May-October. A developer offers 1 MW of capacity from a BTM storage device located at a metalworking facility with physical capability of 2 MW, 4 hour duration. Device had received an SGIP incentive and was put into operation over 1 year ago.

- **<u>Utility Position</u>:**

  - SCE and PG&E believe that the storage described in this use case would be considered partially incremental, consistent with the method and matrix approved by the CPUC in the IDER Pilot RFO. Fundamentally, the Offeror needs to demonstrate that the offered capacity/energy is different from what otherwise would have occurred, i.e., different from the expected use. MUA Rule 11 adequately covers this use case and consistent with this Rule and the IDER definition of incrementality, the Offeror has the burden to demonstrate that the offered service is incremental to expected use under SGIP and therefore eligible to compete in the RFP. If selected in the competitive process, the actual compensation is based on performance and delivery of service agreed upon between the buyer and the seller. Said differently, incrementality - - measured as "above expected use" - - would determine how much of the offer is eligible to participate, and if the resource's offered service is selected, the payment is based on actual performance and delivery of the transacted service.
    - Payment for the RFO-related capacity discharge, if not distinct from SGIP related discharge, would likely constitute double payment.
  - SCE and PG&E also believe that the SGIP's program rules require certain amounts of charging and discharging. The distribution system operator, when determining a need for additional resources, must rely on SCADA data that would already reflect the storage resource's past operating profile. Furthermore, it is conceivable that the distribution system planners might make assumptions regarding storage's future operating profile, consistent with the CPUC definition about future expected use based on participation in other programs, such as TOU bill management. The Offeror knows the specific services (time, quantity, dispatch duration, etc.) that the utility is looking for and has the burden to demonstrate during the procurement process that the product they are offering is different from what the utility would expect.
  - PG&E notes that the CPUC is currently engaged in an extensive effort to improve the SGIP program, including addressing GHG emissions. PG&E cautions that until that effort results in specific SGIP program requirements, it is premature to draw conclusions about what "incrementality" means for customers installing storage who receive SGIP incentives.

- SDG&E does not consider any service funded under the existing SGIP resources as incremental. SDG&E highlights that the SGIP was established legislatively in 2001 and intended to help address peak electricity problems (i.e. provide capacity through load reduction) and deliver other grid benefits in California. The CPUC Measurement & Evaluation (M&E) plan as part of SGIP calls for a series of annual impact evaluations that are focused on SGIP energy storage projects, including: net greenhouse gas (GHG) emissions associated with the operation of storage systems; timing and duration of charge and discharge on average; quantify any contribution of storage projects to grid services where that storage substituted for and replaced planned investment.[60] The outcome of these evaluations is set as the basis of SGIP program modifications, as necessary.

  Since SGIP resources are already being paid and monitored to provide grid services, including distribution capacity, in exchange for SGIP incentives, any additional payment for distribution capacity would be double compensation. Additionally, the current SGIP methodology assumes that all storage devices charge during off-peak hours and discharge during peak hours.
  The methodology estimates net emission impacts using the emission rate of a new CT as a proxy for the emissions avoided by reducing demand during peak hours and the emission rate of a new CCGT plant as proxy for the emissions created by increasing demand during the off-peak hours.[61] Energy Division staff, with CESA's input, decided that when charging during off peak and discharging at peak with a round-trip efficiency above 64%, the storage device would automatically reduce GHGs and therefore qualify for SGIP funding.[62] It is SDG&E's understanding that the SGIP impact evaluation team found that all storage project types are in fact *increasing* GHG emissions (emphasis added), and that the residential projects appear to be providing primarily power outage backup benefits to customers. Providing backup power to customers is not a stated goal of the SGIP program. The SGIP evaluation team recommended that additional performance metrics, such as the difference between the system-level average emissions rate at discharge and at charge, be developed for program eligibility requirements as they relate to GHG emissions.[63]

  If SGIP energy storage devices are not being used to help shave the peak and reduce GHGs, the mechanism for determining SGIP benefits and corresponding incentives needs to be modified to reflect this unanticipated result. Unanticipated SGIP results highlight some of the key challenges with programmatic and tariff based solutions, as these types of solutions don't typically elicit the intended behavioral response. It is problematic to define "incrementality" on the base of tariffs or programs that produce outcomes that are inconsistent with what was intended. Using such anticipated results as the base, will lead to inefficient procurement of DERs and drive up overall system

60 Public Utilities Code § 379.6
61 D. 15-11-027
62 R. 12-11-005
63 2016 SGIP ADVANCED ENERGY STORAGE IMPACT EVALUATION

costs. SDG&E believes that unless and until the existing SGIP is modified to bring the SGIP subsidy in line with the benefits provided, the storage described in this use case is considered non-incremental.

- **NEM example – RA services**
  - **Example Use Case And Related Questions:**
    - Does energy exported from NEM solar+storage installation qualify as satisfying RA requirement? If so, for a NEM solar+storage installation, how much of the energy exported from the NEM system should qualify as performance in determining RA compensation? Does the incrementality determination change if, at the time the RA contract is signed by the utility, solar+storage is already installed, vs. Storage will be added to an existing solar installation if a contract is signed, vs. solar+storage will be installed new if a contract is signed? Does this change if the installation is not participating in NEM? Against what baseline should any incrementality be measured?
    - Hypothetical scenario: A BTM solar+storage installation is installed for a customer as NEM system, the Resource aggregator registers this system as a DERA and adds this installation as an NGR to an aggregation registered with the CAISO. Battery is directly metered for measurement of performance in the wholesale market.
  - **Utility Position:**
    - CAISO's DERP agreement does not allow storage that is participating in a retail net energy metering program, that does not expressly permit wholesale market participation, to utilize the non-generator resource or participating generator models. Storage provider needs to follow the rules and instructions in the DERP participation agreement, and if modifications are desired, they should be pursued in the relevant forum/proceeding.
    - DERAs currently do not qualify for RA capacity. For BTM contracts, only PDR/RDRR get RA capacity.
    - At this time, all BTM resources (NEM and non-NEM) have been treated by the CEC and the utilities as load modifiers in the load forecast for Resource Adequacy. And as a result, these BTM resources reduce the load serving entity's RA requirements. It would be double-counting if the same BTM storage is counted as a load-modifying demand-side product and then also as a supply-side resource.
    - Energy storage resources can benefit from NEM treatment so long as they are charged by customer-sited solar PV and sized proportionally to the customer's load (demand). This in combination with the additional requirement to enter into a net energy metering successor tariff (NEM 2.0+), should create economic incentives for behavior that benefits the grid (via time of use rates). The operational parameters stemming from these two requirements to qualify for future NEM treatment, directs a specific load modification behavior that charges the battery with excess solar during the day and discharge energy during the peak hours.

- SDG&E believes that because the energy storage resource already has an incentive to modify its load shape in line with system peaking needs, and because this load reduction will be reflected in the demand forecast used to set local and system capacity requirements (i.e., RA requirements), providing RA services in combination with receiving NEM treatment would be double compensation.

▪ NEM energy exports are credited at retail rates for 12 months (after which any net surplus generation is compensated at a retail commodity rate), which reflects the cost to the utility of acquiring various products required to serve customers, including RA capacity. Unless BTM solar+storage exports are to be compensated based on unbundled value components (which is not the case today), the exported energy from the NEM-paired storage should not receive full-retail credit <u>as well as</u> additional revenue from wholesale energy markets. Doing so is clearly double-payment, in part because once receiving full-retail credit, the underlying energy now belongs to the utility and its other customers who are paying at this extraordinarily generous rate.
  - The Offeror can choose to not participate in NEM, if they would rather receive payment from offering commercial products. For example, Demand Energy had indicated that they might prefer to get RA capacity payment through DR participation in the CAISO markets even if it means not getting NEM energy credits.

▪ Customers whose load is completely offset by NEM should not receive another RFO payment for the same load reduction.

▪ Also, sub-metering of a BTM storage unit by itself is not sufficient in measuring grid services, because there needs to be a corresponding effect at the retail meter. Therefore, baselines are critically important in determining incrementality.

▪ SCE has submitted testimony in the RA proceeding (R. 17-09-020) proposing methodologies to account for the amount of RA that a battery could provide when combined with other resources. For behind-the-meter storage applications (i.e., non-WDAT interconnections), the only RA product that can be provided is Demand Response. Therefore, the value of the behind-the-meter storage device is in enabling Demand Response.

- **NEM example – Distribution Deferral Services**

  - **<u>Example Use Case and Related Questions</u>:**

    ▪ Does energy exported from NEM solar+storage installation qualify as satisfying Distribution Deferral requirement? If so, for a NEM solar+storage installation, how much of the energy exported from the NEM system should qualify as performance in determining Distribution Deferral compensation? Does the incrementality determination change if, at the time the Distribution Deferral agreement is signed by the utility, solar+storage is already installed, vs. Storage will be added to an existing solar installation if a contract is signed, vs. solar+storage will be installed new if a contract is signed? Does this change if the installation is not participating in NEM? Against what baseline should any incrementality be measured?

- Hypothetical scenario: A BTM solar+storage installation is installed for a customer as NEM system and the Offeror/Aggregator signs a Distribution Deferral agreement with the utility. When awarded and dispatched pursuant to the Distribution Deferral agreement, battery discharge results in exported energy.

- **Utility Position:**

  - The CPUC's definition of incrementality says that incremental services should be above and beyond what is expected under other programs. Existing NEM storage without any modification (i.e., without utility's operating control or a different operating profile to satisfy utility's need) would not be incremental towards the utility's need, as its operating profile and intent is already assumed in the need determination (e.g., SCADA data).
  - SCE and PG&E believe that existing NEM storage resource that agrees to change storage dispatch to meet Distribution Deferral needs can be partially incremental. However, such BTM storage resources may be difficult to procure for Distribution Deferral because the utility would need to be convinced that capacity offered is viable, which would require sellers to lock down customer profiles for the offered product prior to making a binding offer in the RFO.[64] In doing so, the sellers would have to assume contractual risk that capacity is viable, i.e., otherwise face default and potential penalties.
  - SCE and PG&E believe that value assessment for such incremental storage services would need to adjust for the storage not performing during system peak hours (i.e., otherwise expected use). Also, the exported energy would not receive any additional compensation or different compensation than what the NEM program offers, but the utility would separately value and compensate the Incremental value from the energy storage (e.g., shifting of load that would otherwise not occur). In any case, the shifting of load must be incremental to any load shift in the baseline (e.g., when the customer shifts PV generation to evening hours using the storage).
  - SDG&E believes that any resource under the NEM tariff is non-incremental. Existing NEM treatment directs and generously compensates for a wide range of intended services, including a specific load modification behavior to charge the battery with excess solar during the day and discharge energy during the peak hours. As the energy storage resource already has an incentive to modify its load shape in line with the system peaking needs, and because the net load forecast of the customers is already reflected in distribution planning, SDG&E believes providing distribution deferral capacity services in combination with receiving NEM treatment would be double-compensation.
  - PG&E stresses that the CPUC will soon initiate an OIR to address the NEM program. In addition, the CPUC is also currently addressing the appropriate tariff language for customers on the NEM tariff who install storage. For these

[64] CESA observes that this is what is already being done by BTM aggregators in recent solicitations.

reasons, PG&E suggest that it is premature to determine "incrementality" for customers with storage who are participating in net metering. Until the NEM tariff is determined, and the tariff rules set for the combination of PV and Storage behind the same meter, it is impossible to determine expected behavior, and therefore premature to determine what would constitute incrementality.

- **Recommended Policy Changes**
  - The Utilities do not, at this time, have specific recommendations for the Commission as to how incrementality rules should apply to specific use cases. However, as discussed below, the Utilities do have perspectives on the incrementality of the use cases proffered by the industry stakeholders. The Utilities believe any specific recommendations for the Commission require more experience with BTM storage in multi-use applications.

Multiple Use Applications for Energy Storage Working Group Chapter 4. Incrementality & Rule 11 (Storage Industry Position)	
Lead Drafter:	Ted Ko, Stem and Jin Noh, California Energy Storage Alliance
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1. Synopsis

The California Public Utilities Commission (CPUC) issued Decision (D.) 18-01-003 on January 11, 2018 that adopted a Multiple-Use Application (MUA) Framework for energy storage resources and approved an interim rule in Rule 11 with the stated intention of avoiding double compensation for energy storage resources providing multiple services. The Decision directed the MUA Working Group to consider any potential refinements to this *preliminary* rule.[65]

Specifically, Rule 11 specifies that:[66]

> "In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation."

The key determination in Rule 11 is how much of a service provided is incremental and thus should be counted, credited, and compensated.[67] However, Rule 11 does not provide an explicit definition of "incremental" – leaving it to the MUA Working Group to discuss this issue and provide any recommendations for refinement. Additionally, Rule 11 does not address the degree of accuracy and certainty required to demonstrate incrementality or quantify the level of service provided.

A clear and explicit definition of "incremental" is needed to ensure that energy storage solution providers are fairly paid for their full value of services rendered and that consistent definitions are applied by the IOUs. In most cases of energy storage MUAs, the services provided can be generally assumed to have some non-zero value of incrementality. At the same time, industry stakeholders acknowledge that some flexibility may be needed in applying the definition of incrementality in many cases, but a clearer definition reflected in a modified Rule 11 and proposed new Rule 12 would lay the principles and foundation by which incrementality can be assessed.

There is a wide spectrum of positions on incrementality. An overly narrow view of incrementality may effectively prohibit energy storage providers from providing multiple services and maximizing the value of energy storage assets or may unduly discount the value of the different services rendered. An overly broad view of incrementality may lead to overcompensation for services rendered. Industry stakeholders generally share the view that the adopted incrementality definition should endeavor to

65 Decision *on Multiple-Use Application Issues*, D.18-01-003, issued on January 17, 2018, p. 19. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.pdf

66 *Ibid*, Appendix A: Adopted Rules, p. 2.

67 *Ibid*, Appendix B: Revised Joint Framework Multiple-Use Applications for Energy Storage,

reasonably accommodate energy storage MUAs that maximize ratepayer benefit while not paying more than the value of services provided.

Therefore, pursuant to the Decision, the MUA Working Group began discussion of the incrementality issue during the April 20, 2018 meeting, with follow-up discussions among stakeholders on May 3, 2018 and June 7, 2018. The MUA Working Group focused on developing a definition of "incremental" to guide future design of policies, regulations, and CPUC-approved contracts governing the provision and payment for MUA services.

This report section begins with background on how incrementality has been defined and applied to date in other CPUC and CAISO venues, followed by a summary of some of the key discussions during the MUA Working Group meetings. Informed by the review of the regulatory history and working group discussions, this report includes various recommendations, including a more explicit definition of incrementality, reflected in the following proposed modifications to Rule 11 and in a new proposed Rule 12 in the MUA Framework.

Industry stakeholders recommend the following language change for Rule 11:

> "**Rule 11.** In paying for performance of services, compensation and credit within a domain may only be permitted to the extent that the service provided incremental value to that domain. Value is deemed incremental within a domain to the extent that the units of service provided are additional to the units of service that domain had already expected or counted with reasonable certainty.
>
> The service buyer in each domain is responsible for resolving overcompensation for non-incremental value within that entity's transaction settlement processes. The service buyer can establish a general prohibition on a MUA configuration for compensation concerns only if it has been demonstrated in a transparent and consistent manner that incrementality is zero or *de minimus* for all use cases of that MUA configuration."

Industry suggests the following language for Rule 12:

> "**Rule 12.** In procurement of new services, the service being procured from a MUA resource is incremental to what the service buyer can assume with reasonable certainty (prior to the solicitation) will be provided at comparable levels of locational, temporal, and operational granularity. The service buyer should transparently provide its planning assumptions at the time the solicitation is issued."

Finally, the MUA Working Group discussions revealed that there are competing views and sets of recommendations on the incrementality issue, leading to two different parallel report sections – one from "Industry" (CESA, CALSSA, Stem, EnerNOC, Sunrun, AMS, and others) and one from the investor-owned utilities (PG&E, SCE, and SDG&E). This report section is intended to represent views broadly shared by industry stakeholders, but it also highlights areas where there may be potential areas of commonality and consensus with the IOUs.

2. Background & History

The issue of incrementality has been explored previously by the CPUC and CAISO in a variety of different proceedings and initiatives. This report section highlights three particular procedural venues that delved into the incrementality issue and discusses how incrementality was defined in those venues. Most of these individual incrementality definitions, however, apply to a single domain or jurisdiction, whereas the MUA Working Group intends to address MUA issues pertaining to energy storage resources providing services across multiple, different domains and jurisdictions. Furthermore, the mix of terminology and standards for defining and measuring incrementality across different proceedings and programs creates uncertainty and inconsistency that may strand value that energy storage MUAs could otherwise provide. Thus, while the existing incrementality definitions are helpful as a starting point of discussion, these definitions need to be updated for the multi-jurisdictional MUA Framework for energy storage resources.

2.1 Integrated Distributed Energy Resources (IDER) Competitive Solicitation Framework

The IDER proceeding (R.14-10-003) is tasked with developing sourcing mechanisms to address identified distribution grid needs, including the development of compensation structures, tariffs, incentives, and other tools for procuring distributed energy resources (DERs). A Competitive Solicitation Framework Working Group (CSFWG) was established to develop the framework necessary for DER providers to understand distribution reliability needs and meet the performance requirements that will allow for the deferral of traditional infrastructure. Among the steps identified in the framework, the CSFWG was tasked with developing methodologies to count services provided and to ensure no duplication with procurement in other proceedings.

D.16-12-036, issued on December 22, 2016, provided guidance on the definition of incrementality to be used in the IDER Pilot Request for Offers (RFO). D.16-12-036 stated that the DER service "counting method" should:[68]

- Ensure that ratepayers are not paying twice for the same service;
- Ensure the reliability of a service, i.e., ensure it is not counting on a service to be there when the service might be deployed at another time or place;
- Not be unduly burdensome to participants;
- Be technology-neutral;
- Be fair and consistent;
- Recognize that a distributed energy resource is eligible to provide multiple incremental services and be compensated for each service; and
- Be flexible and transparent to bidders.

In approving the IDER Pilot RFOs, the CPUC also issued Resolution E-4889 that elaborated on the incrementality principles adopted in D.16-12-036, adding that "services offered by existing DERs that are

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[68] Decision *Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot*, D.16-12-036, issued on December 22, 2016, pp. 18-19. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

above and beyond what is expected under other programs should be considered incremental" and that "a resource [that] is compensated through a different program but in the IDER bid is expected to be operated in a different manner than business-as-usual, then this resource should be considered incremental."[69] In conducting the offer evaluations, Resolution E-4889 approved a hybrid incrementality methodology that would divide offers into three tranches based on sourcing mechanism:[70]

- **Tranche 1 - Wholly Incremental:** IDER offers which provide technologies and services not already being sourced or reasonably expected to be sourced through another utility procurement, program, or tariff, and that meet specific identified distribution needs are categorized into Tranche One.
- **Tranche 2 – Partially Incremental:** IDER offers in which some portion of the technology or service is already incentivized through another authorized utility procurement, program, or tariff, and that meet specific identified distribution needs are categorized into Tranche Two. SCE will only consider that portion of the offer that provides enhancement to the existing project as incremental.
- **Tranche 3 – Not Incremental:** IDER offers which provide technologies or services already sourced under another authorized utility procurement, program or tariff that meet the identified distribution need and that provide no clearly discernible incremental value beyond current offerings.

During the MUA Working Group discussions, the IOUs indicated that they believe the D.16-12-036 principles and additional clarifications in Resolution E-4889 are consistent with guidance provided in Rule 11 adopted in D.18-01-003, thus recommending that no changes are needed to Rule 11. However, industry stakeholders believe that the IDER definition of incrementality, though a good starting point, does not provide sufficient clarity to industry on what the IOUs will consider incremental during the competitive solicitation process. In the case of behind-the-meter (BTM) energy storage systems, some services are already committed to the customer that may overlap to some degree with the services requested by the utility. When service providers submit offers into these competitive solicitations, the IOUs need to transparently and accurately consider whether and how much of a service provider's offer is incremental for the purposes of valuing and selecting winning offers, as well as to determine if an incremental service can be provided with greater certainty (in contrast to an assumed likelihood of a dispatch).

Outside of the IDER solicitations, incrementality has been defined on a case-by-case basis in IOU procurements. A key issue, however, is that many competitive solicitations, such as SCE's 2018 Moorpark/Goleta Request for Proposals (RFP), are citing or referring to D.16-12-036 as the framework by which the IOUs will assess incrementality. Additionally, each of the IOUs appear to be assessing incrementality differently.[71] Therefore, this report section is important insofar as it will inform whether

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69 Resolution *E-4889: Approves, with modifications Pacific Gas and Electric Company (PG&E) Advice Letter (AL) 5096-E, Southern California Edison Company (SCE) AL 3620-E/3620-E-A/3620-E-B, and San Diego Gas and Electric Company (SDG&E) AL 3089-E*, issued on December 19, 2017, p. 27. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K961/201961781.PDF

70 *Ibid*, pp. 8, 11.

71 In SCE's Moorpark/Goleta RFP (Attachment F: Incrementality Guidance), BTM energy storage is considered permanent load shifting and is considered incremental when "not being compensated and will not be compensated or reasonably expected to be compensated through existing SCE programs and contracts such as

the IDER incrementality definition appropriately values the incrementality of DER offers into competitive solicitations.

As detailed further in subsequent sections, the IDER incrementality definition does not sufficiently clarify what is expected of DERs to meet the underlying grid 'need'. Parties should thus reasonably question the firmness, certainty, and accuracy of such performance expectations. Also, the IDER incrementality definitions do not account for forms of incrementality other than procurement incrementality.
This report section will thus discuss how a modified Rule 11 and a new proposed Rule 12 compare to the incrementality discussions in the IDER proceeding and assess whether the current Rule 11 aligns with previous incrementality determinations in utility solicitations, providing insight into whether MUA rules need to be changed going forward.

2.2 Demand Response

Several decisions were issued in DR-related proceedings and applications to establish DR dual participation rules that intend to prevent customers from being paid twice for the same capacity while still allowing customers to simultaneously participate in two or more DR programs. Over the years, the dual participation and compensation rules have changed multiple times, effectively reframing the incrementality definition and leading to confusion by DR Service providers.

In 2009, the CPUC issued D.09-08-027, which considered the potential for dual participation in DR programs to expand the level of DR services and minimize ratepayer costs. In that Decision, the CPUC acknowledged the need to avoid double compensation and gaming. In order to do so, D.09-08-027 concluded that customers may participate in two DR programs so long as one provides an energy payment and the other provides a capacity payment.[72] This framework presented new challenges in having to categorize each DR program as either an energy or capacity program even as some programs had elements of both. The CPUC decision also provided rules around simultaneous events (akin to the simultaneous MUA rules needed for energy storage MUAs more broadly) for customers dual-enrolled in DR programs where the customer would only be paid under the capacity program, and established a prohibition around participation in two day-ahead or two day-of programs. Importantly, the CPUC Decision discussed how "it is not consistent with Commission priorities to limit customers' ability to reduce peak demand simply because it *might* result in some customer overpayment in rare circumstances."[73] D.09-08-027 was affirmed in a subsequent CPUC Decision that found that dual participation promoted increased DR participation from customers.[74] Meanwhile, in Electric Rule 24/32, prohibitions are in place that prevent customers from simultaneously participating in a third-party-administered supply-side DR program and an event-based utility-administered DR program.

SCE's PLS program, Local Capacity Requirement (LCR) contracts, or SGIP." By contrast, in PG&E's Q&A for its Oakland Clean Energy Initiative, incrementality is determined by whether projects have SGIP reservations before or after the June 15, 2018 submission date for offers.

72 Decision *Adopting Demand Response Activities and Budgets for 2009 Through 2011*, D.09-08-027, issued on August 20, 2009, pp. 149-150, 154.

73 *Ibid*, pp. 154-155.

74 Decision *Adopting Demand Response Activities and Budgets for 2012 Through 2014*, D.12-04-045, issued on April 30, 2012, p. 56. http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/Graphics/165317.PDF

While the consideration of DR dual participation is currently scoped into the 2018-2022 DR Applications (A.17-01-012, A.17-02-018, and A.17-01-019),[75] Industry believes that the recommendations on the incrementality definitions and principles from the MUA Working Group should inform the update of the DR dual participation rules to ensure consistency across CPUC-jurisdictional DR programs and CAISO market participation rules. Previous CPUC Decisions in the DR proceedings and applications indicate a level of confusion in terminology and rules (such as around energy versus capacity programs, or event-based versus non-event-based programs) that would benefit from clearer incrementality definition and rules developed in this proceeding. The IOUs, however, hold the view that the MUA Working Group should not address the issue here because it is already scoped into the 2018-2022 DR Applications proceeding. While in agreement that the dual participation issue may not be able to be directly addressed in the MUA Working Group process, Industry believes that the MUA Working Group can provide potentially actionable recommendations for consideration in the DR proceeding.

This portion of the report below discusses how Rule 11 and a new proposed Rule 12 can apply to the incrementality discussions in the DR proceeding.

2.3 Performance Evaluation Methodologies

Incrementality also refers to the quantification of the actual performance of services by an energy storage resource as measured by the market or contractual expectation of the resource's performance. Such measurements often determine the compensation for services rendered, making it a critically important metric both on the front end in pricing such services and on the back end in providing certainty to revenues over the term of the performance obligation. While incrementality based on resource performance expectation may be applicable to a range of resources, this issue is especially relevant to DR services, where compensation is based on measured load reductions relative to the expectation of load. The CAISO's metered generator output (MGO) baseline, approved in 2016 by the CAISO and FERC, is an example of a performance evaluation methodology that evaluates a directly-metered resource's wholesale energy market performance in the Proxy Demand Resource (PDR) model during "event" days against a baseline of resource performance during 10 previous "non-event" days. Incrementality in this case has been defined as performance of a service relative to the "typical use" or past use of the resource.

The MGO Baseline methodology was originally developed in the CAISO's Energy Storage and Distributed Energy Resources (ESDER) Phase 1 Initiative because the available performance evaluation methodologies at the time did not separately measure the DR provided by a BTM energy storage device and the facility's total load, leading to less accurate determinations and overly conservative approaches to measuring "typical use" that possibly undercompensated energy storage MUAs providing retail customer services. For example, during hours in which a BTM energy storage resource was providing

[75] A Ruling scheduled a workshop on February 13, 2018 to discuss the current DR dual participation rules and consider proposals to revise the rules in response to concerns of possible disparate treatment of utility DR program customers and third-party DR program customers in regards to these dual participation rules. At the workshop, the Administrative Law Judge indicated that a Scoping Memo or Ruling would be issued to summarize the workshop and discuss next steps on how to proceed on this issue in the 2018-2022 DR Applications. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M206/K793/206793025.PDF.

retail customer services (*e.g.*, demand charge reductions, time-of-use arbitrage) outside of the CAISO market, the non-MGO baseline approaches would not accurately capture this out-of-market activity in setting the baseline by which to measure the performance of a BTM energy storage resource when it was dispatched in the CAISO market, leading to under-compensation for the load reductions provided by the resource relative to typical use. By accurately measuring previous behavior through the MGO Baseline methodology, the BTM energy storage resource's incremental performance is more accurately and fairly recorded and compensated.[76]

As the current ESDER initiative provides a ready opportunity for updating baseline and related incrementality approaches, while specifically referencing the CPUC's MUA Working Group, this report provides a timely opportunity to provide broad recommendations for consideration in other proceedings and initiatives like ESDER, even if the actual determination of whether and what recommendations to adopt cannot be determined in the MUA Working Group.

This section of the report below details how industry stakeholders believe that performance evaluation methodologies should reasonably and accurately measure the incremental performance of energy storage resources. Accurately accounting for expected use in baseline methodologies is one example of how performance evaluation methodologies can be improved and reflected in correct applications of Rule 11.

3. Proposed Incrementality Definitions and Framework

The MUA Working Group discussions revealed differing views on incrementality and whether additional changes or modifications are needed. The IOUs believe that the current Rule 11 in the MUA Framework as adopted in D.18-01-003 and the incrementality determinations already made in other CPUC proceedings and CAISO stakeholder initiatives, as discussed in Section 2 above, are adequate.
These approaches, while laudable, should be further clarified, made transparent, and improved upon to ensure the incremental value of services offered and rendered are accurately and fairly assessed and compensated, as well as to ensure proper and consistent resource modeling within planning processes across the IOUs. This viewpoint was broadly supported by industry who face propositions of putting 'at risk' capital forth in order to pursue MUAs. As MUAs benefit ratepayers through lower-cost services, rules should reasonably balance between the goals of leveraging existing policy work while also supporting the competitive deployments of MUAs. In the section below, perspectives on a new incrementality framework, building off the policy development in other proceedings and initiatives, are offered. To illustrate how this new incrementality framework would be applied, this report section also details several specific MUA scenarios.

Industry stakeholders generally share the view that incrementality should be defined within three distinct categories below, as presented by Stem at the second MUA Working Group meeting on May 3,

[76] Working Group discussions demonstrated a tendency to conflate the MGO Baseline with traditional 10-in-10 DR baselines in the incrementality discussion. For clarity, MGO is a performance evaluation methodology used to replace the customer retail meter DR Baseline methodology. The MGO Baseline was added to the MGO methodology to account for incrementality in a multi-use configuration. The traditional 10-in-10 DR baseline is not designed to determine incrementality. It is designed to estimate a counterfactual for measuring single-use performance.

2018. The incrementality categories proposed below have been slightly modified and clarified since it was initially presented.

3.1 Planning & Procurement Incrementality

A planning and procurement incrementality category determines incrementality for an identified grid need during the *planning and solicitation processes*. This *ex ante* incrementality is a determination of how much energy and capacity of a resource is incremental to address an identified grid need and how much of that incremental energy and capacity should be reflected in procurement contracts, tariffs, and programs.

At a high-level, competitive solicitations for specific grid needs (*e.g.*, RA, distribution deferral) typically arise out of a grid planning process that forecasts existing and future load, load-modifying resource deployments, and supply resources. Underlying these forecasts are a set of assumptions on the operational profile, timing of deployment, and siting of grid-connected resources, which have varying degrees of certainty and accuracy by which grid needs can be identified and incrementality definitions can be assessed. While grid planning assumptions and models already incorporate certain resources based on program and policy expectations, the opportunity of MUAs is prompting the need to vet or further detail these assumptions to support incrementality determinations.

All planning assumptions are subject to some degree of uncertainty and inaccuracy. These assumptions set an "expected" (or sometimes referred to in other proceedings as the "autonomous") trajectory of load and load-modifying resources based on policies and programs that drive the adoption of those resources. For example, the Net Energy Metering (NEM) tariff is expected to drive a certain level of rooftop solar growth given the economics of installing these systems at various customer sites, and the Self-Generation Incentive Program (SGIP) is expected to drive a certain level of customer-sited energy storage due to upfront and/or performance-based incentives. While these tariffs and programs may drive customer adoption of these load-modifying technologies, MUA discussions have revealed that many assumptions made in forecasting models may lack detail regarding when and where these systems will be deployed, as well as how these resources will operate, or change operations under changing rates or other conditions. The combined effect of these assumptions determines the underlying grid need, which may then be addressed in a subsequent competitive solicitation.

These planning assumptions must be assessed for certainty and accuracy in making the planning and procurement incrementality determination. Take the assumed operational profile of SGIP-funded projects, for example. The California Energy Commission (CEC) incorporated energy storage impacts in the system-level load forecast for the first time in its 2017 Integrated Energy Policy Report (IEPR), where it sourced data from SGIP, assumed a 90% peak impact relative to nameplate capacity for projects based on a review of performance-based incentive (PBI) project data,[77] and assumed a constant rate of additions over the forecast period.[78] Given the broad and linear nature of these assumptions, it is

[77] California *Energy Demand 2018-2030 Revised Forecast*, 17-IEPR-03, submitted April 19, 2018, pp. 36, A-14. https://efiling.energy.ca.gov/GetDocument.aspx?tn=223244

[78] In addition, the CEC explained that, while responses and load impacts to TOU rates are incorporated into the IEPR analysis, these responses are not specific to energy storage. CESA participated in the DRP Distribution

reasonable to assume that there may be inaccuracies and uncertainties underpinning these operational assumptions. First, the planning assumptions may inaccurately assume an operational profile based on a faulty assumption of the project's objective, such as system peak load reduction when the project is in fact addressing other rate elements such as non-coincident demand charges. Second, the planning assumptions may incorrectly assume the certainty of a specific operational profile for particular objective given the complexity of rate designs, load shapes, other economic signals, etc. Finally, the IOUs must make additional assumptions on how these system-level forecasts disaggregate down to specific circuits and feeders on their distribution grid.

Although the IOUs have stated that load forecasts can be based on "rational response" to economic signals in rates and tariffs, energy storage operations can be particularly challenging to assume. Given the ability of technology like energy storage to shape load, there are a wide range of very different load profiles that are all equally economically rational for volumetric rates, such as TOU rates, and these profiles could be changed arbitrarily over time by customers based on exogenous factors while remaining entirely rational. This reduces the certainty of load forecasts and points to the fact that the specific discharge patterns as required to deliver RA or distribution deferral value over the long term are incremental to 'rational' usage.

While planning assumptions must still be used, a key takeaway is that, in many cases, some incrementality exists that could be obscured through generalized planning assumptions. That is, due to these uncertainties, industry stakeholders find it reasonable to assume or explore some non-zero level of incrementality for some existing and new (but "expected") energy storage projects offering their services to address an identified grid need, **particularly when they offer to be contractually committed to operational profiles that differ from those used in the planning assumptions**. However, to make this incrementality determination, it may be reasonable to help IOUs gain visibility into the operational profile of existing resources by, say, requiring bidders to submit this information when vying for planning capacity procurements. As it currently stands, the onus is on the bidders to make this case on how their submitted resource will provide incremental grid services to the IOU – either through firmed or changed operations in response to the grid service. The CPUC affirmed this in some ways by requiring that "Bidders must be convincing in presenting a plan that will result in incremental savings relative to existing programs, and must include a robust methodology to verify claimable (incremental) savings and avoid any possible double-counting of savings."[79]

However, to fairly assess incrementality and provide clarity to service providers on how to price bids, the IOUs should equivalently support industry efforts to determine incrementality via additional transparency on utility planning assumptions, such as the type and number of DER deployments expected in the specific locations of need, the assumed operations of those DERs, and the associated impacts of those operations on the identified grid need. The CPUC affirmed that bidders need this type of information to help them "provide meaningful bids,"[80] though the CPUC deferred this issue to the

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Forecasting Working Group where the CEC indicated that it is working to come up with a better and/or more predictive approach. The CEC noted that it did not explicitly model system adoption and rather used "trend analysis". See slides from the CEC during the May 16, 2018 Distribution Forecasting Working Group meeting: http://capabilities.itron.com/DFWG/documents/Fugate%20-%20PV%20-%20DFWG%205-16.pdf

[79] Resolution E-4889, p. 29.

[80] *Ibid*, p. 32.

DRP proceeding when approving the IDER Pilot RFO solicitation design. Furthermore, this transparency from the IOUs will also help to vet the veracity of their incrementality determinations, which may impact solicitation eligibility and evaluation of bids/offers. Thus, this MUA report provides the opportunity to direct some further sharing by utilities on planning assumptions with the goal to support MUA incrementality for purposes of providing grid services, etc.

The need for a consistent, transparent methodology for determining incrementality within IOU solicitations necessitates the proposed new MUA Rule 12. Rule 12 fundamentally seeks to avoid leaving value on the table, with a goal of prudently supporting competition by MUAs. As discussed, varying "black box" approaches to assessing the incrementality of offers increases barriers to and uncertainty in the solicitation process, which increases costs to ratepayers. Furthermore, overly conservative incrementality determinations potentially lead to over-procurement, again requiring ratepayers to pay for more services than is necessary. The new proposed Rule 12 detailing the principles of a planning and procurement incrementality category thus makes important distinctions with compensation incrementality, which is discussed further in the next section. Overall, Rule 12 would be a reasonable and useful addition to the existing suite of rules established by (D.) 18-01-003.

Industry stakeholders strongly recommend that the Commission adopt Rule 12 and establish rules whereby any solicitation must provide the precise methodology by which incrementality will be assessed at the time the solicitation is issued. While the burden is currently on the bidders and offerors to submit their existing or proposed project information to demonstrate incrementality, Industry recommends that the IOUs should also be directed to provide transparency into their underlying planning assumptions to allow consistent, fair, and reasonable qualification and enforcement of planning and procurement incrementality. The methodology must be sufficiently detailed such that the offeror can calculate how much their offer will be incremental relative to the planning assumptions for the solicited service in that specific area of the grid. While such work may involve more updated approaches to procurement and planning efforts, such approaches seem appropriate and in line with the ongoing evolution of practices used in the California grid, as well as in line with policy goals to leverage MUAs or DERs.

Finally, a principles-based incrementality methodology has little reason to materially vary between IOUs for the same MUA configuration. While baseline planning assumptions will vary by IOU and by local grid area, the methodology by which an offer is deemed incremental to those assumptions should be a consistent Commission-approved methodology.

Scenario #1: SGIP Incentive

The issue of whether SGIP-funded projects are eligible and incremental has come up in recent IOU solicitations. To illustrate an example, say that an IOU issues a distribution deferral RFO for distribution capacity resources that can perform for two hours with a call window between 3 pm and 9 pm on any weekday between May and October. The developer offers 1 MW of capacity from a BTM energy storage resource located at a customer facility with the physical capability of 2 MW and 4-hour duration, but this device has also received an SGIP incentive and was put into operation over a year ago.

The key question that arises in this context is, "How much of the offer's capacity is considered incremental?"

In these cases, market participants have indicated that utilities have required the offeror of a grid service to demonstrate how the offered energy or capacity differs from what otherwise would have occurred (*i.e.*, the expected use) to determine eligibility and, if eligible, the level of incrementality. For purposes here, it is important to note that SGIP's rules require certain amounts of charging and discharging but not the provision of specific grid services. A distribution grid operator, when determining a need for additional resources, must rely on SCADA data to determine the past operating profile and so might make assumptions regarding the energy storage system's future operating profile, consistent with the rate structures and SGIP program requirements. With such assumptions, one might thus assume the existing Rule 11 and partially incremental rules are sufficient, where the offeror must demonstrate that the offer is different from what the IOU might have expected.

Industry stakeholders have a different view where Rule 11 focuses strictly on the compensation and financial settlement from the actual performance of services rather than more broadly covering the eligibility, bid/offer evaluation, resource qualification(s), and contracting of services to be performed. Viewed in this way, the MUA rules should clarify that planning and procurement incrementality should be based on the service being procured, not the quantity of the hardware.[81] Industry stakeholders therefore disagree that Rule 11 adequately captures this nuance and thus proposes a new Rule 12 to cover and make a distinction with planning and procurement incrementality.

Additionally, in this specific example, industry stakeholders view SGIP as a technology deployment program using an incentive based on the kWh of hardware deployed. Industry stakeholders and the IOUs appear to be in agreement that, while the program has grid service objectives, a specific grid service is not being provided or procured through the program's operational and performance requirements. Thus, the grid operator cannot reliably 'count' on any service being provided by the SGIP-funded energy storage system receiving the incentive. The difference in perspective between the IOUs and Industry lies in how certain the assumed operational profile of an SGIP-funded energy storage system is given the program's requirements. Industry differs from the IOU viewpoint in that acceptance of an SGIP incentive does not guarantee a specific operational profile.

SGIP also includes multiple program goals, such as GHG emissions reduction, that may make the predictability of energy storage dispatch difficult. The two primary operational requirements in SGIP, the annual cycle requirement and the Round Trip Efficiency (RTE), both provide no certainty of an operational profile. As has been demonstrated in the evaluation of the SGIP, different storage systems will meet those requirements with widely varying operational strategies.

Thus, because no operational profile of an SGIP-funded system can be assumed with sufficient certainty, the receipt of an SGIP incentive has no bearing on the determination of incrementality in the procurement process. Incrementality may be determined on an expected operational profile of an energy storage installation of the offered size, but that calculation is still independent of whether that particular installation received an incentive. With the given example, the methodology could take the historical performance of the energy storage system within the specified 3 pm to 9 pm windows, May through October as establishing expected use, but this has nothing to do with that system's receipt of the SGIP incentive.

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81 Resolution E-4889 alludes to this by focusing on the services offered by existing DERs rather than whether the DER hardware was already sourced elsewhere.

Accordingly, industry stakeholders differentiate SGIP-funded energy storage systems from energy storage systems that participate in a specific program, such as a DR program, that "procures" and compensates for a specific grid service, where a specific operational profile can be more reasonably assumed to be certain and included in utility planning assumptions.

In all such procurement scenarios, a new energy storage system installed as a result of a contract awarded in the solicitation is fully incremental. Because the system is new, it was not providing any of the solicited capacity previously. And expected deployment under the existing programs cannot provide sufficient certainty that the exact service being solicited is going to be provided.

Therefore, industry stakeholders recommend that the Commission establish precedent whereby the receipt of a financial incentive is mostly or entirely irrelevant to the provision of services, *e.g.*, accessing the Federal investment tax credit, energy star rebate, or receiving SGIP incentives. A technology incentive has no bearing on the eligibility in an IOU procurement solicitation. The incrementality of such a resource should be based on the extent to which a resource's existence and operations inform the need calculation. To be clear, this point is focused on getting a technology incentive only. Industry recognizes that energy storage systems that happen to have received SGIP incentives could be subject to the same incrementality assessments as energy storage systems that do not receive SGIP. In terms of eligibility, however, the fact that the host customer received some form of an incentive, such as a tax credit, is not a relevant factor in evaluating the developer's offer into the solicitation. Industry recognizes that systems that receive incentives may have been 'planned for', and so may have some less-than-100% amount of incrementality to the system. So long as planning assumptions are reasonable, fair, and explained (likely at the front end of a solicitation), it may be reasonable for utilities to assume non-incrementality of the total capacity of some systems.

Thus, the Commission should re-examine previous Commission approved solicitations where developers were prohibited from offering storage systems that had or would receive the SGIP incentive. In light of an updated understanding of incrementality and potential new procurement rules, such prohibitions may prove to be no longer valid. Industry notes again that PG&E's recent "Oakland Clean Energy Initiative" noted all SGIP systems as incremental if interconnected after a certain date. This highlights how the capacity can be incremental, even if the resource received some out of market (and mostly or entirely unrelated to specific services) incentive, tax credit, etc.

Scenario #2: NEM Paired Storage

Energy storage systems are allowed to interconnect under the NEM tariff to enhance the NEM-eligible solar generator. However, given that NEM generation is compensated at retail energy rates and are viewed as load-modifying resources in load forecasts, the IOUs have sometimes excluded NEM generators from competitive solicitations. However, again, greater transparency into how NEM forecasts are fed into IOU planning assumptions are needed. For example, are NEM-tied forecasts expecting systems to be deployed as standalone NEM or NEM-paired storage facilities? If both, what is the proportion for each? These types of assumptions are important to the incremental determination at the planning and procurement stage.

There are some key planning and procurement incrementality questions tied to whether NEM systems are incremental:

- Does energy exported from the NEM-paired storage installation qualify as satisfying the RA requirement?
- Does the incrementality determination change if the NEM-paired storage system is already installed – *i.e.*, only requires operational and contractual commitment to firm or change operations?
- Does the incrementality determination change if energy storage will be added to an existing solar installation?
- Does the incrementality determination change if the NEM-paired storage will be wholly new and installed due to the procurement contract?

As an example, let's say a residential customer has 3 kW of load now being served by the dispatched battery and has another 7 kW of export capacity available with sufficient energy storage reserves to meet the RA must-offer obligation dispatch with 10 kW of capacity. There is no public policy benefit of preventing additional coincidental capacity to meet the needs of the grid and instead favor limiting the capacity potential to self-consumption. It is unknown today how future participation models will offset the need for utility infrastructure investments and meet the highly variable needs of the grid, but facilitating dispatched exports, when allowed by the interconnection agreement as MUAs, may enable the full capacity of these dynamic storage resources to be unlocked for utilization of the grid.

In an RA procurement, exported and self-consumed energy can provide the same amount of capacity, so it is reasonable to consider whether both types of energy should be treated the same when assessed for incrementality. As an example, ISO New England (ISO-NE) has passive DR programs that enable NEM generation, whether co-located with energy storage or not, to take on additional RA commitments. Eligible generators receive NEM credits from the distribution utility, but no ISO-NE energy payment for the capacity they have committed to and are providing to the system. This market participation model enables additional capacity to meet the coincidental needs of the power system and ensures no overcompensation for the services provided.

In addition to the incrementality assessment for NEM-paired storage systems providing RA capacity, an incrementality assessment is appropriate for NEM-paired storage systems that bid to provide distribution deferral capacity. Similar to Scenario #1, simply participating in NEM should not automatically make NEM-paired storage systems ineligible for competitive solicitations for distribution deferral capacity. A more detailed incrementality assessment is needed to determine the degree to which the NEM-paired storage system is incremental, which depends on the responses to the questions above (*e.g.*, incrementality relative to the planning assumptions based on firmed or changed operations, adding storage to an existing NEM generator, or wholly installing a new NEM-paired storage system in specific locations).

For an existing NEM system without energy storage, the amount of capacity being provided prior to the RFP can be calculated based on the historical performance of the system. If the NEM system has energy storage, that calculation is much less certain but can be reasonably shown to be greater than zero, depending on the incremental service commitments to firm or changed operations (*e.g.*, exports versus self-consumption at certain times). However, it is clear that an incrementality determination is a case-by-case calculation or reasonable methodology based on resource planning profiles, thus blanket NEM prohibitions cannot be justified.

It should be noted that in Working Group discussions, the IOUs expressed the qualitative opinion that the incrementality value of systems that received the SGIP incentive or NEM compensation should be discounted based on the idea that SGIP and NEM are "very rich" and ratepayers are paying "significantly in excess of the value of services provided". To avoid subjectivity and re-litigation of decisions around incentives or compensation, it should be made clear that incrementality must be done on a principle-oriented basis, from which quantitative measurements flow, and not the reverse. Furthermore, as has been discussed above, incrementality should entirely be based on compensation for value provided, independent of any discussion of the appropriate level of unrelated incentives or compensation for unrelated services. The Commission should clearly reject any suggestion of relating these issues to incrementality.

3.2 Compensation & Service Incrementality

Industry stakeholders propose a separate compensation and service incrementality category differentiated from procurement and planning incrementality in that the former determines *ex ante* incrementality whereas the latter assesses *ex post* incrementality that may not be factored into contracts and settlement mechanisms at the time of procurement and contract execution. In other words, after resources have been procured, there may be "value left on the table" that is not fully accounted for and compensated. However, at the same time, if the planning and procurement phase fully accounts for the incrementality of actual services rendered, then there may not be a compensation and service incrementality issue (see example below).

There may also be other markets where resources do not need to be solicited through a procurement and separately contracted (*e.g.*, energy markets) but rendering of actual services is measured through performance evaluation methodology or governed by tariffs. Compensation and service incrementality come into play in these cases as well, with industry stakeholders holding the view that these compensation structures must fully account for and compensate the full, actual services rendered. Again, if expected use is accurately reflected in, for example, load scheduling in the case of DR resources, then there may not be a compensation and service incrementality issue.

Scenario #3: MGO Baseline

The MGO methodology improved upon the PDR performance evaluation methodology for BTM resources that could be directly metered. The MGO Baseline was added to the "North American Energy Standards Board (NAESB) like" MGO methodology in order to determine incrementality beyond service provided to the retail customer. During the MUA Working Group discussions, Stem raised the compensation incrementality issue on how the current MGO baseline methodology does not fully account for the full demand reductions provided by the BTM energy storage device as determined by "typical use".

The MGO Baseline was ostensibly designed to remove the "typical use" of the battery from the performance measurement during the wholesale market event. The stated justification was that the energy provided is only incremental beyond what the resource "was going to do anyway." This justification does not adhere to the proposed definition of incrementality because energy provided should be considered incremental beyond what the market **expected the resource to do in that domain**. What the battery "was going to do anyway" is not necessarily the same as what the market "expected" from a forward-looking perspective. During the MUA Working Group meetings, it was determined that in this MUA scenario, because the CAISO did generally incorporate previous non-event days load activity into the load forecast for the event day, "typical use" and "expected use" is considered equivalent. While the IOUs and CAISO stated that the distinction between typical use and expected use is unnecessary, industry stakeholders assert that this should be made clear in the Commission's rules in order to ensure that future compensation incrementality methodologies are not justified on "typical use".

A potential compensation and service incrementality issue with the MGO Baseline does arise, however, when the baseline measurement does not incorporate the full charge and discharge operations of the BTM energy storage device. The MGO Baseline measures the BTM energy storage resource's impact on load in the previous 10 non-event days to calculate the baseline. Battery discharging is measured as a positive kW number, while charging is measured as a negative number. However, to calculate the baseline, all charging measurements (negative numbers) are set to zero.

For example, let's say a BTM energy storage resource provides TOU bill management to the customer and also participates in the CAISO's PDR mechanism. The resource has elected to use the CAISO's approved MGO Baseline method for performance evaluation, using Option B2 (Measuring the Direct Battery Meter Only). On the event day, the resource is dispatched to discharge 3 MW for 1 hour (3 MWh) at 2 PM. The first row of the table below shows the battery's operations on the 10 previous similar days, during non-event hours, where positive numbers convey energy storage discharge to curtail facility load while negative numbers represent energy storage charge.

Days	1	2	3	4	5	6	7	8	9	10	Event
Battery Dispatch (MW)	1	2	-2	-3	-3	-1	0	1	1	2	3
Baseline Under Net Export Rule (MW)	1	2	0	0	0	0	0	1	1	2	

Taking the average of the 10 previous similar days, non-event hours, the baseline is set 0.7 MW, leading to an incremental load reduction of 2.3 MW. However, if the baseline incorporated the negative discharge (or positive charge) number as part of the expected use of the resource, then the baseline would be set at -0.1 MW, leading to an incremental load reduction of 3.1 MW. Thus, the current MGO Baseline violates the incrementality definition of expected use and fails to fully compensate for the incremental value of services rendered.

Note that the MGO Baseline example shows how Rule 11 should not be focused on preventing "double compensation" for the "same service". The objective of determining incrementality is to prevent the overcompensation for a service beyond the incremental value a resource provides in that domain. The MGO Baseline does this calculation irrespective of whether the two services are defined as the "same service". In fact, in the Commission's efforts to date, these two services would not be classified as the same service: different domains, energy versus capacity, etc. Thus, the Industry's proposed changes to Rule 11 remove these terms.

Scenario #4: Simultaneous MUAs

Important considerations for determining the compensation and service incrementality of simultaneous MUAs are the following:

- Are the two services provided by the simultaneous MUA distinct and valuable? If not for the energy storage MUA, would the service buying entity for one of the two services need to otherwise buy the service from an alternative resource?
- Are the two services provided by the simultaneous MUA part of two separate markets – *e.g.*, separately priced and procured?

Even though the IOUs may argue that the same energy or capacity should not be paid twice, it is reasonable to consider whether energy storage MUAs should be paid for all the services that they provide. It seems inappropriate to determine that one service should be provided for “free” just because it is provided simultaneously with another service.

Stepping back, simultaneous MUAs represent maximizing efficient use of capital assets for the grid and they should be encouraged. While an individual instance of simultaneous MUA may seem like an asset is receiving overcompensation, the optimally efficient situation is that a single capital asset, likely as part of an aggregation of assets, can do "double duty" for multiple other capital assets that might otherwise be required. Because these other multiple capital assets might not be congruent in their deployment timelines, operational needs, and so forth, it may take substantial effort to successfully effect long-term deferral of multiple investments with a single DER or set of DERs. It is this efficient outcome that justifies encouraging simultaneous MUAs in addition to the principle that assets should not be forced to perform services for "free".

Scenario 5: Demand Response Dual Participation

DR dual participation rules that were established to prevent “double counting” should be considered a subset, or corollaries of the final MUA Rules that the Commission adopts. While the MUA WG was scoped from the Energy Storage proceeding, in order for the Commission to be internally consistent, the principles and concepts that are clarified here should be used to update the rules in, at a minimum, those other contexts where storage can participate, notably DR programs and IDER procurements.

The clearest such implications from the MUA WG deliberations come from the distinction between time-differentiated, capacity differentiated and simultaneous MUAs. The WG concluded that MUA services that are clearly time-differentiated do not have an overcompensation issue and thus are not subject to an incrementality determination. A simple MUA configuration that demonstrates this concept is an energy storage device that is providing distribution deferral for several months and system RA in different months. The WG also concluded that MUA services that are capacity differentiated – *i.e.*, different physical capacity is being used to provide each service – are also not subject to incrementality determination.

DR dual participation rules do not contemplate participation in multiple DR programs that are either time-differentiated or capacity-differentiated. Thus, at a minimum, the DR dual participation rules should be updated to reflect that a customer may participate in any combination of DR programs in either a time-differentiated or capacity differentiated configuration.

For example, consider a 1-MW BTM energy storage system. A customer registers 400 kW in the Base Interruptible Program (BIP) and 600 kW in an aggregator's local capacity requirement (LCR) contract with the distribution utility. There's no double-counting risk or reliability risk involved as long as the customer load is always above 1 MW during periods where call windows overlap. As such the customer should be allowed to dual participate in BIP and the LCR contract.

With respect to simultaneous MUAs, the DR dual participation rules should be updated to reflect the incrementality framework established with the MUA rules, rather than general rules based on a tangle of classifications. Whether or not a DR program or tariff is load-modifying or supply side, energy or capacity, or event-based or non-event based, resolution of potential overcompensation should be resolved based on an incrementality determination, not broad prohibitions.

Additionally, during Working Group discussions, the IOUs raised the issue of performance evaluation methodologies measuring the performance of a BTM asset with the asset's direct sub-meter rather than looking at the net-effect of all the resources on the customer premises at the customer's retail meter. Their contention was that all performance should be measured as the net-effect at the retail meter. This policy issue is well outside the scope of the MUA Working Group but has a direct effect on the prospects for DR Dual Participation (especially capacity-differentiated MUA). The industry maintains that this question has been resolved in favor of measurement at the asset level, not the customer premises level, with the FERC approval of the CAISO MGO methodology. Further exploration of this topic can be found in the Asset Separation Principle described in Stem's comments to FERC on DER participation in wholesale markets.[82]

3.3 Compliance Incrementality

Compliance incrementality is another category of incrementality that ensures that entities subject to specific policy and mandate requirements do not double count their progress or compliance toward meeting these requirements. This type of incrementality may determine the incremental policy or mandate need as opposed to the identified grid need. In many ways, these policies and mandates are already reflected in the IOU planning assumptions, as they, for example, incorporate Renewable Portfolio Standard (RPS) requirements to meet a certain percentage of retail sales from eligible renewable resources through 2030 and Assembly Bill (AB) 2514 requirements to procure 1,325 MW of energy storage across three domains by 2020. Various rules are in place to ensure that there is no double counting of meeting compliance obligations – *e.g.*, customer-domain storage procured through an AB 2514 solicitation cannot also be counted against the IOU procurement obligation if it also participates in SGIP.

[82] "Post-Technical Conference Comments of Stem, Inc.,", Stem, Inc. June 26, 2018, filed in FERC proceeding RM18-9, p. 19

However, considering the other two incrementality categories above, Industry believes that compliance incrementality should not automatically exclude resources during the procurement and compensation incrementality assessment. It is essential to distinguish the capacity of a technology deployed to meet a compliance obligation from the exact services provided. For example, if an IOU has met its AB 2514 energy storage procurement targets but has still identified a grid need for which energy storage would address, the IOU should not be prevented from procuring the energy storage resource and making separate incrementality assessments along Industry's other two proposed incrementality categories, even as there is no compliance incrementality for procuring the energy storage resource. As stated previously, detailed planning assumptions must be provided regarding the location, timing, certainty, and operational profile of resources deployed in order to determine incrementality, rather than enforcing a blanket prohibition on resources procured to meet compliance obligations at a territory-wide level. This incrementality category is noted here in this report section to clarify that Industry views this additional incrementality category as important when determining whether new or existing resources meet an identified policy "need" or deficiency.

4. Industry Recommendations

Correctly defining and assessing incrementality is important to enable the greater utilization of both existing and new energy storage assets and to fairly and appropriately compensate energy storage resources for the full value of actual services rendered, while reasonably identifying situations where inappropriate double compensation is avoided. This report section discusses the Industry's views on how incrementality should be defined, which differs from that of the IOUs, who believe that the current Rule 11 combined with incrementality definitions and methodologies developed in other proceedings and initiatives are sufficient to cover the range of use cases on a case-by-case basis.

Industry stakeholders believe that treatment in Rule 11 of compensation and service incrementality must be clarified and that an additional rule, Rule 12, needs to be established to address the potential "value on the table" for services procured and rendered. To the degree that Rule 12 planning and procurement incrementality does not account for the full value of actual services rendered, then Rule 11 principles apply.

Thus, industry stakeholders propose the following modified Rule 11:

> "**Rule 11.** In paying for performance of services, compensation and credit within a domain may only be permitted to the extent that the service provided incremental value to that domain. Value is deemed incremental within a domain to the extent that the units of service provided are additional to the units of service that domain had already expected or counted with reasonable certainty.
>
> The service buyer in each domain is responsible for resolving overcompensation for non-incremental value within that entity's transaction settlement processes. The service buyer can establish a general prohibition on a MUA configuration for compensation concerns if it has been demonstrated in a transparent and consistent manner that incrementality is zero or *de minimus* for all use cases of that MUA configuration."

It is important to note that application of Rule 11 should not be limited to the utilization of event-based or non-event-based baseline methods, especially as resource participation models evolve. Going forward, it may be feasible to use historical metering data to establish expected use and record dispatch responses to assess incremental value, services, and compensation.

Furthermore, compensation and service incrementality (Rule 11) must be differentiated from planning and procurement incrementality, as reflected in a new proposed Rule 12:

> "**Rule 12.** In procurement of new services, the service being procured from a MUA resource is incremental to what the service buyer can assume with reasonable certainty (prior to the solicitation) will be provided at comparable levels of locational, temporal, and operational granularity. The service buyer should transparently provide its planning assumptions at the time the solicitation is issued."

While Rule 12 can often be viewed from a more limited competitive solicitation framework, Industry recommends that planning and procurement incrementality be applied to other sourcing frameworks as well. The IDER proceeding is considering the development of "alternative" sourcing mechanisms, which include tariffs and programs, that will guide new operational characteristics and/or autonomous grid support capabilities. Resources under these grid-support tariffs or programs will need to be fed back into planning assumptions, and vice versa, to support incrementality assessments in procuring for services to meet identified grid needs. From this resource planning perspective, we must move beyond load-modifying behavior modeling to DER resource modeling in order to ensure accurate, consistent and transparent assumptions, as well as their utilization to document resource qualification and model incremental service profiles impacts for planning and operations.

Within the Rule 12 context, industry further recommends the following:

- All solicitations must provide planning assumptions and a transparent upfront incrementality methodology.
- For the same MUA configuration (e.g., local capacity and NEM), the incrementality methodology should be consistent across all Commission regulated LSEs.
- Offerors will then provide production profile(s) of the offered resource(s) and justification for incrementality based on the given methodology.
- Solicitations and procurement contracts cannot apply blanket prohibitions against resources participating in a competitive solicitation based on their receiving a technology deployment incentive, unless the incentive requires the resource to provide the precise service that is being procured.
- Accordingly, the Commission should re-examine previous solicitations that included such prohibitions.

Finally, many of the recommendations in this report section will require coordination with other proceedings. The goal of this report section is to adopt the two above rules to provide guidance on how incrementality should be assessed in these other proceedings and initiatives to ensure consistency across agencies and load-serving entities in procuring and compensating for grid services.

Specifically, with respect to Demand Response Dual Participation, Industry recommends:

- Concepts of time-differentiated and capacity differentiated MUAs should be incorporated into the update of the DR dual participation rules
- DR dual participation rules that were established to prevent overcompensation in simultaneous DR programs should be updated to adopt an incrementality framework rather than program by program prohibitions.

In conclusion, Industry hopes that this report section conveys that there is no “perfect answer” to incrementality, and even with the principles of and guidance from the above proposed modified Rule 11 and new Rule 12, Industry understands that the incrementality definitions and assessments may still need to be done on a case-by-case basis in some instances. However, with improved principles and guidance, energy storage MUAs will be deemed eligible as appropriate and assessed for some appropriate level of incrementality that ensures that value is not left on the table.

Multiple Use Applications for Energy Storage Working Group Chapter 5. Ensuring Resource Performance (Rules 6 – 10)	
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1. Synopsis

This chapter includes recommendations on Rules 6 through 10 in the MUA Decision, D.18-01-003, which relate to ensuring resource performance for energy storage resources that provide MUA. The Working Group agrees with the Decision's position on the value of MUA and acknowledges the added benefits of storage with MUA (as compared to storage with only a single-use-application). Storage with MUA can provide additional value to both energy storage customers and the electric grid. At the same time, without the proper rules and regulations in place to ensure resources perform as needed, MUA value may be hindered or potentially eliminated. As such, the Working Group provides recommendations on ways to maximize benefits for MUA, while maintaining and ensuring storage performance. The Rules established herein should facilitate MUA, while not being unduly burdensome for storage resources (as compared to other resources).

As a starting point for considering recommendations to address under-performance or non-performance, the Working Group discussed using contracts, such as those used for interconnection (*i.e.*, Generator Interconnection Agreements), for market participation, or for other services. Contracts may provide a solid basis upon which to assume performance and to safeguard against non-performance. This is in line with practices used today for services being provided in all four domains.

During Working Group meetings grid operators (both distribution and transmission) raised special considerations relating to the 'primacy' or 'supremacy' of their needs over other services. Working Group stakeholders actively explored how MUAs might create unique challenges that differ from some of the challenges and existing solutions in place today. In general, many of the challenges are the same, but some MUA-specific issues did arise, which are discussed further in this chapter.

This chapter discusses two over-arching issues for ensuring resource performance for MUAs:

- **<u>Issue 1: Storage devices with capacity-differentiated MUA could be designated to provide two or more services that may conflict in dispatch</u>.** In cases where the resource's performance does not match with the net of the capacity-differentiated dispatches, it may help to pre-determine which dispatch is deemed to be under-delivered, or if a pro rata 'deviation' from dispatch is applied equally amongst the jurisdictions being served.
    - Countervailing dispatches and needs between the distribution and transmission/market system are conceivable due to the disconnected nature and differing jurisdictions of management of these systems. Today's operations can cause similar outcomes.
    - Capacity-differentiated MUA can result in conflicting simultaneous operations. Just as with today's operations, the inability of the distribution system operator to know of

market, customer, or transmission actions, can cause cases where changes in other domains may offset the distribution-focused dispatch. This could potentially compromise reliability both at the distribution and system level resulting in no party receiving the reliability service required.
    - A decision must be made with respect to which entity receives priority in determining the storage dispatch, and during what periods of time to avoid conflicting signals / instructions / operations, reliability problems, or inappropriate compensation.
    - Primacy rules regulating "override" instructions, in scenarios where conflicts exist, could address this problem.
- **<u>Issue 2: The MUA Decision (D. 18-01-003) prohibits one resource from delivering two or more reliability services at the same time if the performance of one obligation renders the resource from being unable to perform the other obligation. The granularity of time periods can range from monthly to perhaps sub-hourly</u>.**
    - Resource Adequacy (RA) and distribution deferral are both considered reliability services
    - RA has an advanced showing requirement (Year ahead / month ahead for calendar month)
        - Any resources shown for RA can arguably only provide RA, as no other reliability activity has such advanced and long duration requirements
        - ***Though this is important for safeguarding reliability, the design seems at odds with the spirit of MUA***
    - It is possible for a resource to provide both RA and distribution deferral value in a single month – however, forecasting needs and real-time operations would have to be worked out accordingly.
    - CAISO is exploring defining time periods based on the nature of the service provided, in the Storage as Transmission Asset (SATA)
    - Utility distribution management systems may benefit from incorporating abilities to perform month/week/day ahead forecasting to further the ability to predict when reliability services would be required for the distribution system for any forecasting timeframe more granular than seasonal. In fact, the IOUs are working to improve in such capacities, and anticipate that doing so will help to ascertain whether a given MUA storage device can meet reliability needs identified.

This chapter includes the following five recommendations[83] to address the issues outlined above:

<u>Recommendation 1: Primacy in dispatch should belong to the entity consistent with the point of interconnection where reliability services are being provided in multiple domains.</u>

If the point of interconnection is on the distribution system, primacy would lie with the Distribution Utility and if the point of interconnection is on the transmission system, primacy would lie with the CAISO. The CPUC Should Adopt the Principle that the Distribution Service Operator (DSO) has Dispatch Primacy for Distribution-Connected Resources. The CPUC should consider whether changes in

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83 While this document focuses examples on providing distribution reliability and RA, the concepts, can be applied to any multiple reliability provision at any level (i.e. distribution, transmission, or RA).

Evaluation Protocols are needed to establish "Deliverability" (Net Qualifying Capacity) for distribution-connected resources.

Recommendation 2: With the evolution of distributed energy resources (DERs), the deliverability construct for RA should continue to be examined to determine if and how processes can improve to ensure that multiple reliability services can be provided by DERs. In the meantime, the capacity provided for multiple reliability services from such DERs should be evaluated for its ability to provide the given service considering the potential conflicts.

Recommendation 3: The CPUC should Open an Order Instituting Rulemaking to Assess Minimum Performance Standards for ES Providing Multiple Reliability Services

The CPUC should consider a future Order Instituting Rulemaking (OIR) related to RA, which would analyze and develop the parameters necessary to allow resources to provide RA as well as other reliability services without overly relying on such resources for one reliability service given their incremental uncertainty due to the provision of a second reliability service.

When contracting for resources to meet reliability needs of the utility, the utility – in their procurement process – evaluates the efficacy of resources providing multiple reliability services in meeting the procurement need. Such evaluation is then to be included in the application/advice letter to the Commission for approval of such contracts.

Recommendation 4: The CAISO should continue to evaluate its Resource Adequacy Availability Incentive Mechanism (RAAIM) to ensure that it continues to provide appropriate incentive to RA resources to make their capacity available as required. In addition, contracts by the utilities to procure a reliability service from a storage device could contain within the terms and conditions any necessary penalty, payment reductions/revocations and/or default/contract termination if the resource fails to provide the reliability service or meet certain performance thresholds.

Such contract provisions should be reviewed in the utility's application or advice letter filing.[84] Alternatively, more explicit 'market price signals' for services may inform MUA operations and replacement, as is the case with RA replacement, or some wholesale services today. MUAs should not be burdened with excessive or onerous provisions if their services are not procured to ensure reliable operation of the grid or such reliable operation can be provided without excessive or onerous provisions. Doing so is in the best interest of the market for both buyers and sellers of MUA resources and end-use ratepayers.

These issues and recommendations are discussed in further detail, below.

[84] SCE presumes that, during the development of MUA, the utilities will file applications or advice letters for approval of such contracts. If MUA develops sufficient standards in the future, such applications or advice letter filings may become unnecessary.

2. Issues and Recommendations

2.1 Issue 1—Capacity-differentiated MUA could provide two services that may conflict in dispatch

Issue Statement:
A storage device participating in capacity-differentiated MUA services could potentially receive two conflicting signals for dispatch. For example, in an extreme case, a storage device may receive a signal to charge during a certain period of the day, and an equal and opposite signal to discharge at the same period, in which case the signals cancel one another out entirely and that resource is compensated while not providing the incremental generation or load that it was dispatched to provide.

Presently, resources interconnecting to provide energy storage do so with provisions that the utility may curtail their charging or instruct the resource to discontinue charging if such actions threaten the reliability and safety of the distribution system.[85] Thus, at present, two resources on the same circuit -- even at separate locations--if given conflicting dispatches that threaten distribution reliability or safety, can be addressed by the distribution utility instructing the resources accordingly. Where such conflict occurs from within a single resource, the result should not be treated differently.[86]

This issue was noted during Working Group discussions on this topic, and the CAISO and the distribution utilities acknowledged that with the increase in DERs and the provision of multiple uses, the monitoring and communications between the CAISO and the distribution utility would need to be improved to avoid conflicting instructions. During the Working Group discussions, participants indicated that work was progressing to make such monitoring and communication practical for future use and that development would likely need to occur as implementation of DERs increase. Improvements to these monitoring, communications, and information sharing tools will be particularly important in managing these conflicting signal issues whereby energy storage resources can potentially procure replacement resources (*e.g.*, in the case of RA) for one reliability service to ensure the provision of the other reliability service.

The Working Group also discussed which entity should have primacy in the event of a conflict (*i.e.*, which entity ultimately had the right to over-ride instructions from the other). There was general agreement that such primacy should lie with the distribution utility if the resource was interconnected to the distribution system since 1) a failure of the distribution circuit at which the resource is connected would prevent the resource from providing service to the wholesale market as well; 2) the locational need on the distribution system would likely offer few resources to address the concern, whereas locational need at the wholesale level would likely have more alternatives to address the need; and 3) the distribution system not receiving relief could cause component failure resulting in outages for customers connected to the distribution feeder(s) where the DERs failed to operate.

[85] This is accomplished through the Rule 21 interconnection process and the wholesale distribution tariff for resources providing wholesale services.

[86] In the event that the instructions (if offsetting) from the two entities do not cause a reliability concern for either entity, it is acceptable for the resource to be considered to have performed, even if the two instructions offset one another.

Since the present MUA rules do not allow a higher domain to provide services in a lower domain, it is then logical that resources interconnected to the Transmission system would not be providing a reliability service to the distribution system. As such, the CAISO would have primacy over such a resource. More generally then, primacy should lie with the entity that operates the system at which the resource has interconnected if providing a reliability service in multiple domains.

2.1.1 Recommendations to Address Issue 1:

Recommendation 1:

Primacy in dispatch should belong to the entity consistent with the point of interconnection where reliability services are being provided in multiple domains. If the point of interconnection is on the distribution system, primacy would lie with the Distribution Utility and if the point of interconnection is on the transmission system, primacy would lie with the CAISO.[87]

This issue implicates the ability to provide multiple reliability services from a capacity differentiated resource. That is, if the resource is providing a reliability service in the wholesale market (e.g. Resource Adequacy (RA)) and is subject to conflicting instruction from the distribution utility, can it reasonably provide the needed reliability to the wholesale market? It was noted that this issue exists currently in that utility Demand Response (DR) programs provide not only RA but can also be utilized by the distribution utility to address distribution system needs. Since DR is a use-limited program, a demand reduction call for distribution purposes may make the program unavailable to the CAISO for a demand reduction pursuant to RA. This present issue is relatively small given the amount of DR available and the relatively low probability that a demand reduction call by the distribution utility would occur in a manner that makes the resource unavailable to the CAISO for RA purposes. However, in an environment with increasing reliance on such resources, it is not clear that this potential conflict will remain unlikely to arise causing one or the other reliability service to become unavailable. During the April 5, 2018 Working Group meeting SCE explained that the likelihood of this scenario occurring is both highly local and highly dependent of local loads and the distribution level asset. CESA notes that, to the degree that CAISO and utility planning can forecast potential overlapping signals (which depend on the certainty of the timing of the service need), these conflicting signals can potentially be minimized to ensure the provision of both reliability services, while acknowledging that measures and parameters need to be in place to address the instances in which these potential conflicting signals occur.

The Working Group discussed potential solutions to this issue and focused on the concept of making RA deliverability to encompass not only the transmission system but the distribution system as well. The distribution utilities noted that given the relatively higher frequency of circuit switching, guaranteeing deliverability of RA on the distribution system is not a trivial task and has the potential to be costly and

[87] CAISO states that it disagrees that point of interconnection should be the determining factor for primacy; believing, rather, that primacy should be determined in the resource's participation agreements and / or based on which services / markets the resource provides a majority of the time. SCE does not agree that frequency is the issue. For example, if primacy is only needed for distribution reliability once every 10 years and the storage device provides RA every hour, a single event in which a service is not available for the distribution system could result in a potential failure of the distribution grid.

time consuming in both the study process and the potential upgrades necessary to ensure such deliverability.

Recommendation 2:

With the evolution of distributed energy resources (DERs), the deliverability construct for RA should continue to be examined to determine if and how processes can improve to ensure that multiple reliability services can be provided by DERs. In the meantime, the capacity provided for multiple reliability services from such DERs should be evaluated for its ability to provide the given service in light of the potential conflicts.

2.2 Issue 2 –Time-differentiated or Simultaneous MUAs could provide multiple reliability services that may or may not conflict with one another

2.2.1 Issue Statement:

At present, Rule 6 states: Priority means that a single storage resource may not contract for two or more different reliability services from the same capacity in a single, or multiple, domains, over the same or overlapping time interval for which the resource is committed to perform or be available. The storage provider must not enter into multiple reliability service obligations such that the performance of one obligation renders the resource from being unable to perform the other obligation.

An interpretation of this rule could be that a resource providing RA would be ineligible to provide any other reliability service for the entire month in which it is claimed as RA since the RA reliability obligation is for the entire month. However, this interpretation is excessively strong as it is not assured that the provision of RA even for the entire month would "render the resource from being unable to perform the other obligation." In addition to the excessively long duration of a monthly RA obligation serving as the basis for the prohibition of providing multiple reliability services at the same or overlapping time interval, SCE discussed that the issue of performing each obligation really comes down to the coincidence of the need. Simply put, any procurement of capacity to meet a reliability need is performed in order to dispatch the resource for its purpose (energy, voltage support, etc.). In the case where the resource is needed for two reliability needs that occur at the same moment in time (Simultaneous MUA), and the dispatch of the resource is of the same type to satisfy each need (e.g. a dispatch of energy from the reliability capacity procured) then there is no conflict and the capacity served each purpose.

In the other extreme case, it is feasible that a battery device may be needed during a single day at times sufficiently separated such that the device could be recharged between uses and would remain available to provide both reliability services. In the case above as well as this case, neither use would "render the resource from being unable to perform the other obligation." In concept, both cases would not render the DER unable to perform both reliability services. However, significant coordination and day/hour ahead forecasting capabilities are required for distribution system operators to realize these cases.

The final example is one in which there is either an overlap of time need or insufficient time to recharge the device to provide the second service. In such cases, the device may perform some or none of the second service due to the conflict.

Establishing that the need is truly on a dispatch basis, the potential to provide multiple reliability services from a single device is possible. The issue then must surround the probability of the two reliability services coming in conflict and how to limit the reliance on the MUA resource based upon the nature of the potential conflict which could include a reduction in countable capacity for the reliability service, a restriction in how many multiple use resources can be relied upon to provide the reliability service, and if the conflict is severe enough (i.e. in terms of frequency of conflict and consequences of the conflict) could result in not allowing the resource to provide both services.

To provide a bit more detail on each of these options, a look at similar concepts in reliability is warranted. As a general matter, reliability concepts do not guarantee 100% reliability as there are simply too many variables to account for in order to safeguard against a load curtailment cost effectively.

For example, the RA program is designed to be able to provide sufficient energy to the grid as well as sufficient operating reserves for the forecast peak load from only those resources claimed to meet the RA requirement. If one knew exactly the peak load and which resources would not experience and outage, as well as the actual availability of imports relied up to meet RA, this would be a simple exercise. However, load forecasts do not have perfect foresight, generation outages do occur, and the conditions in surrounding Balancing Authority areas which would allow imports can change as can the transmission system configuration.

Based on this, it was clear that simply requiring RA to meet peak load plus operating reserves would not be sufficient. Evaluations were made to ascertain the likelihood of outages (transmission and generation), load forecast uncertainty, and import capabilities. Based on these evaluations, the RA program was developed to forecast load for system RA requirements on a 1-in-2 year basis (meaning there is a 50% likelihood that the actual peak load will be less than the forecast peak load), allow for derates, allocate import capability, and apply a planning reserve margin to arrive at the type and quantity of dependable capacity to meet system load needs. For local RA, the RA program uses 1-in-10 year (meaning there is a 90% likelihood that the actual peak load will be less than the forecast peak load), and historic import levels, and then applies the most severe contingency condition (the over-lapping outage of two facilities) to arrive at the required quantity of dependable capacity. This system has functioned well since its original design with no outages caused by a lack of generating capacity.

In addition, programs were put in place to provide financial incentives to procure a sufficient amount of resources[88] and incentives to make the RA dedicated capacity available to the CAISO market.[89] Taken in

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[88] The CPUC can penalize a Load Serving Entity within its jurisdiction if it fails to procure the amount of capacity that is required of it.

[89] The CAISO has instituted the Resource Adequacy Availability Incentive Mechanism which provides incentive payments for availability above a threshold and charges for availability below a threshold.

its entirety, the combination of CPUC and CAISO regulation provides a reasonable assurance that resources will be available to meet load need.

In the case of MUAs, energy storage providing multiple services increases the probability of unavailability of the resource to provide RA due to the provision of multiple reliability services. Much like the probability of an outage, the probability of a conflicting dispatch can and should be accounted for in making decisions to procure a single resource to perform two reliability functions.

Finally, the RA program for System and Local RA was designed to meet peak loads but recognizes that the loads need to be met in all hours. Requiring a resource to be available in all hours to meet a peak load need was not a reasonable expectation. A variety of resources have use limitations.[90] It was recognized that a certain amount of resources that are not available in all hours could still meet the peak load needs. However, it was also recognized that if all of an RA need was met by such resources, there would be an insufficient amount of resources to meet load in the non-peak hours. This issue led to the introduction of Marginal Cumulative Capacity (MCC) buckets to restrict the amount of capacity that has a limited operating duration to provide RA.

A similar concept could be extended to the use of battery storage to provide multiple reliability services. That is, the reliability service could restrict (either through regulation or contract) the amount of resources with multiple reliability obligations that can be utilized to meet the reliability service. Such a process would need to consider the primacy issue discussed earlier to determine which reliability service is at risk for non-performance in the event of a conflict.

The ability to predict *a priori* the frequency of conflicts and the severity of consequences at this point is difficult. There may need to be a period of time as the implementation of such multiple services occurs in which the CAISO, the Distribution Utilities, and the CPUC learn about the variety of applications of multiple reliability services. During this time, it may be necessary to establish limitations, counting methodologies, and incentives based upon the case at hand. In doing so, as patterns emerge, more standard rules may be developed that reduce the reliance on a case-by-case analysis. While such a process may be time consuming and will not provide absolute certainty to the market (both the buyer and seller), it is a worthwhile process in order to allow resources to provide the maximum value that they can while allowing consumers to fulfill reliability needs to an acceptable level at the lowest cost practical under the circumstances.

[90] DR is limited by the willingness of a customer to voluntarily curtail their load. Resources with limited fuel supply can only operate a certain number of hours (e.g. hydro and storage), and some resources are limited by regulation (e.g. air emission permit restrictions).

2.2.2 Recommendations to Address Issue 2:

Recommendation 3:

A future Order Instituting Rulemaking related to RA should analyze and develop the parameters necessary to allow resources to provide RA as well as other reliability services without overly relying on such resources for one reliability service given their incremental uncertainty due to the provision of a second reliability service. Similarly, when contracting for resources to meet reliability needs of the utility, the utility should in their procurement evaluate the efficacy of resources providing multiple reliability service in meeting the procurement need. Such evaluation should then be included in the application/advice letter to the Commission for approval of such contracts.

Finally, the workshops discussed potential penalty mechanisms for reliability resources failing to perform the reliability service. The CAISO currently has a penalty mechanism in place for resources failing to provide RA. This penalty is significant and has historically been shown to provide sufficient incentive to ensure that resources remain available to the CAISO or are replaced/substituted with other resources that can provide the service. In addition, there may be contractual terms between the seller of RA and the buyer that could deny (or reduce) capacity payments under the contract if the resource cannot be counted as meeting the full (or meet in part) RA compliance obligation. To complete this set of incentives, it will likely be necessary for the buyer of other reliability services to specify in the contract the penalties or payment revocations that will occur should the resource fail to provide the reliability service.

Recommendation 4:

The CAISO should continue to evaluate its Resource Adequacy Availability Incentive Mechanism (RAAIM) to ensure that it continues to provide appropriate incentive to RA resources to make available their capacity as required. In addition, contracts by the utilities to procure a reliability service from a storage device could contain within the terms and conditions any necessary penalty, payment reductions/revocations, and/or default/contract termination provisions if the resource fails to provide the reliability service or meet certain performance thresholds. Such contract provisions would be reviewed in the utilities application or advice letter filing. Alternatively, more explicit 'market price signals' for services may inform MUA operations and replacement, as is the case with RA replacement, or some wholesale services today. MUAs should not be burdened with excessive or onerous provisions if they do not ensure reliable operation of the grid or such reliable operation can be provided without excessive or onerous provisions. Doing so is in the best interest of the market for both buyers and sellers of MUA resources and end-use ratepayers.

Discussion at the July 23, 2018 Working Group Meeting: SDG&E raised the point that there may be an unresolved conflict in the Commission's MUA ES decision inasmuch as the Commission determined that the provision of "Resource Adequacy" (RA) capacity is a "reliability service" while the provision of wholesale "energy" is a "non-reliability service."[91] According to SDG&E, the conflict arises because an IFM ES resource can satisfy its RA availability obligation under the CAISO tariff by submitting into the CAISO market, an "energy" schedule or a price/quantity offer to provide "energy." Since energy is considered fungible, the unplanned failure of an IFM ES resource to fully deliver on its energy schedule is not considered a threat to reliability and is not a basis for penalizing the IFM ES resource.[92]

Accordingly, while SDG&E is in firm agreement that grid reliability is paramount, SDG&E also believes it is possible that an IFM ES resource acting in good faith could satisfy its RA obligation in the CAISO's day-ahead energy market and -- if subsequently required by the DSO to discharge or charge to provide a distribution reliability service in conflict with the IFM ES resource's day-ahead energy schedule – deviate in real-time from its energy market schedule. In this circumstance, RA capacity was provided to the CAISO's satisfaction, the distribution reliability service was provided to the DSO's satisfaction, and the IFM ES resource would receive an RA capacity payment from a CAISO Load Serving Entity, a distribution reliability service capacity payment from the DSO, and an uninstructed energy settlement from the CAISO.

It has been suggested by some that the simultaneous provision of RA capacity and distribution reliability services for the same ES capacity is impermissible given that the Commission has deemed both services reliability services. However, as the above discussion illustrates, it is unclear that any reliability conflict actually exists in the situation where the RA capacity availability obligation is satisfied via an energy schedule. (There clearly would be a reliability conflict if the RA capacity availability obligation were satisfied through an ancillary service schedule; the Commission has deemed the provision of ancillary service capacity a reliability service.)

Based on the discussion at the July 23, 2018 working group meeting, there appears to be general agreement that the simultaneous provision of RA capacity and distribution reliability services from IFOM ES is not categorically precluded. Contracting parties would, however, need to consider the potential risks and costs. For example, uninstructed deviation settlements may not fully cover variable operating costs. Additionally, if schedule deviations were frequent, significant, and disruptive, it is possible that the CAISO could initiate efforts to impose penalties or other remedies such as "no pay." (Failure to honor an ancillary service obligation is already subject to "no pay.")

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91 SCE does not share this viewpoint.

92 Note that the unplanned failure to fully deliver on an energy schedule is far different from failing to make RA capacity available to the CAISO because of an unplanned outage. There is no penalty for the former. As noted in the discussion above, penalties for the latter can be severe.